PB82-226465

Combustion Modification Controls for Stationary Gas Turbine. Volume I: Environmental Assessment

Acurex Corp.
Mountain View, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

Jul 81

U.S. Department of Commerce
National Technical Information Service
NTIS

PB82-226465

EPA-600/7-81-122a
July 1981

COMBUSTION MODIFICATION CONTROLS FOR STATIONARY GAS TURBINE
VOLUME I: ENVIRONMENTAL ASSESSMENT

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Acurex Final Report FR-79-18/EE

Prepared for
EPA Project Officer -- J. S. Bowen

Combustion Research Branch
Energy Assessment and Control Division
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North Carolina 27711

Contract 68-02-2160

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-81-122a

2.

3. RECIPIENT'S ACCESSION NO. PB82 226465

4. TITLE AND SUBTITLE Combustion Modification Controls for Stationary Gas Turbine: Volume I. Environmental Assessment

5. REPORT DATE July 1981

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S) R. Larkin, H.I. Lips, R.S. Merrill, and K.J. Lim

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Acurex/Energy and Environmental Division
485 Clyde Avenue
Mountain View, California 94042

10. PROGRAM ELEMENT NO. EHE624A

11. CONTRACT/GRANT NO. 68-02-2160

12. SPONSORING AGENCY NAME AND ADDRESS
EPA, Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED Task Final; 2/78-6/80

14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Joshua S. Bowen, Mail Drop 65, 919/541-2470.

16. ABSTRACT The report gives an environmental assessment of combustion modification techniques for stationary gas turbines, with respect to NOx control effectiveness, operational impact, thermal efficiency impact, control costs, and effect on emissions of pollutants other than NOx. Wet controls, which inject steam or water directly into the combustion chamber, are the only available methods sufficiently developed to reduce NOx below the recently recommended New Source Performance Standard of 75 ppm NO_2 at 15% O_2 for clean fuels (greater than 50% reduction). However, the effectiveness of wet controls decreases significantly as the percentage of fuel-bound nitrogen increases. Emissions of unburned hydrocarbons and CO can increase with wet controls; however, a detailed Level 1 test on a 60-MW utility gas turbine indicated that incremental emissions other than NOx remained relatively unchanged. Wet controls increase the cost of electricity by 2-5% due, in large part, to the associated fuel penalty. Dry NOx controls are being developed based on combustor modifications that do not involve water or steam injection. They are promising because of their NOx control effectiveness for both clean and dirty fuels, and their expected lower operational and cost impacts.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Gas Turbines	Stationary Sources	13G
Combustion Control	Combustion Modification	21B
Assessments	Environmental Assessment	14B

18. DISTRIBUTION STATEMENT Release to Public

19. SECURITY CLASS *(This Report)* Unclassified

20. SECURITY CLASS *(This page)* Unclassified

21. NO. OF PAGES

[illegible]

EPA Form 2220-1 (9-73)

ABSTRACT

The report provides an environmental assessment of combustion modification techniques for stationary gas turbines with respect to NO_x control effectiveness, operational impact, thermal efficiency impact, control costs, and effect on emissions of pollutants other than NO_x. Wet controls, which inject steam or water directly into the combustion chamber, are the only currently available methods sufficiently developed to reduce NO_x emissions below the recently recommended New Source Performance Standard of 75 ppm NO_2 at 15 percent O_2 for clean fuels (greater than 50 percent reduction). However, the effectiveness of wet controls decreases significantly as the percentage of fuel-bound nitrogen increases. Emissions of unburned hydrocarbons and CO can increase with wet controls; however, a detailed level 1 test on a 60-MW utility gas turbine indicated that incremental emissions other than NO_x remained relatively unchanged. Wet controls increase the cost of electricity by 2 to 5 percent due, in large part, to the associated fuel penalty. Dry NO_x controls are under development, based on combustor modifications that do not involve water or steam injection. They hold much promise because of their NO_x control effectiveness for both clean and dirty fuels, and their expected lower operational and cost impacts.

PREFACE

This is the third in a series of five process engineering reports to be documented in the "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x EA). Specifically, this report documents the environmental assessment of stationary gas turbines, with primary emphasis on NO_x combustion controls. The NO_x EA, a 36 month program which began in July 1976, is sponsored by the Combustion Research Branch of the Industrial and Environmental Research Laboratory of EPA (IERL-RTP). The program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls applied to these sources, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000.

The NO_x EA will assess the following combination of process parameters and environmental impacts:

- Major fuel combustion stationary NO_x sources: utility boilers, industrial boilers, gas turbines, internal combustion (IC) engines, and commercial and residential warm air furnaces. Other sources (including mobile and noncombustion) will be considered only to the extent that they are needed to determine the NO_x contribution from stationary combustion sources.
- Conventional and alternate gaseous, liquid and solid fuels
- Combustion modification NO_x controls with potential for implementation to the year 2000; other controls (tail gas cleaning, mobile controls) will be considered only to estimate the future need for combustion modifications

- Source effluent streams potentially affected by NO_x controls
- Primary and secondary gaseous, liquid and solid pollutants potentially affected by NO_x controls
- Pollutant impacts on human health and terrestrial or aquatic ecology

To achieve the objectives discussed above, the NO_x EA program approach is structured as shown schematically in Figure P-1. The two major tasks are: Environmental Assessment and Process Engineering (Task B5), and Systems Analysis (Task C). Each of these tasks is designed to achieve one of the overall objectives of the NO_x EA program cited earlier. In Task B5, of which this report is a part, the environmental, economic, and operational impacts of specific source/control combinations will be evaluated. On the basis of this assessment, the incremental multimedia impacts from the use of combustion modification NO_x controls will be identified and ranked. Task C will in turn use the results of Task B5 to identify and rank the most effective source/control combinations to comply, on a local basis, with the current NO_2 air quality standards and projected NO_2 related standards.

As shown in Figure P-1, the key tasks supporting Tasks B5 and C are Baseline Emissions Characterization (Task B1), Evaluation of Emission Impacts and Standards (Task B2), Experimental Testing (Task B3), and Source Analysis Modeling (Task D). The arrows in Figure P-1 show the sequence of subtasks and the major interactions among the tasks. The oval symbols identify the major outputs of each task. The subtasks under each main task are shown on the figure from the top to the bottom of the page in roughly the same order in which they will be carried out.

As indicated above, this report is a part of the Process Engineering and Environmental Assessment Task. The goal of this task is to generate process evaluations and environmental assessments for specific source/control combinations. These studies will be done in order of descending priority. In the first year of the NO_x EA, all the sources and controls involved in current and planned NO_x control implementation programs were investigated. The "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference P-1) documented this effort

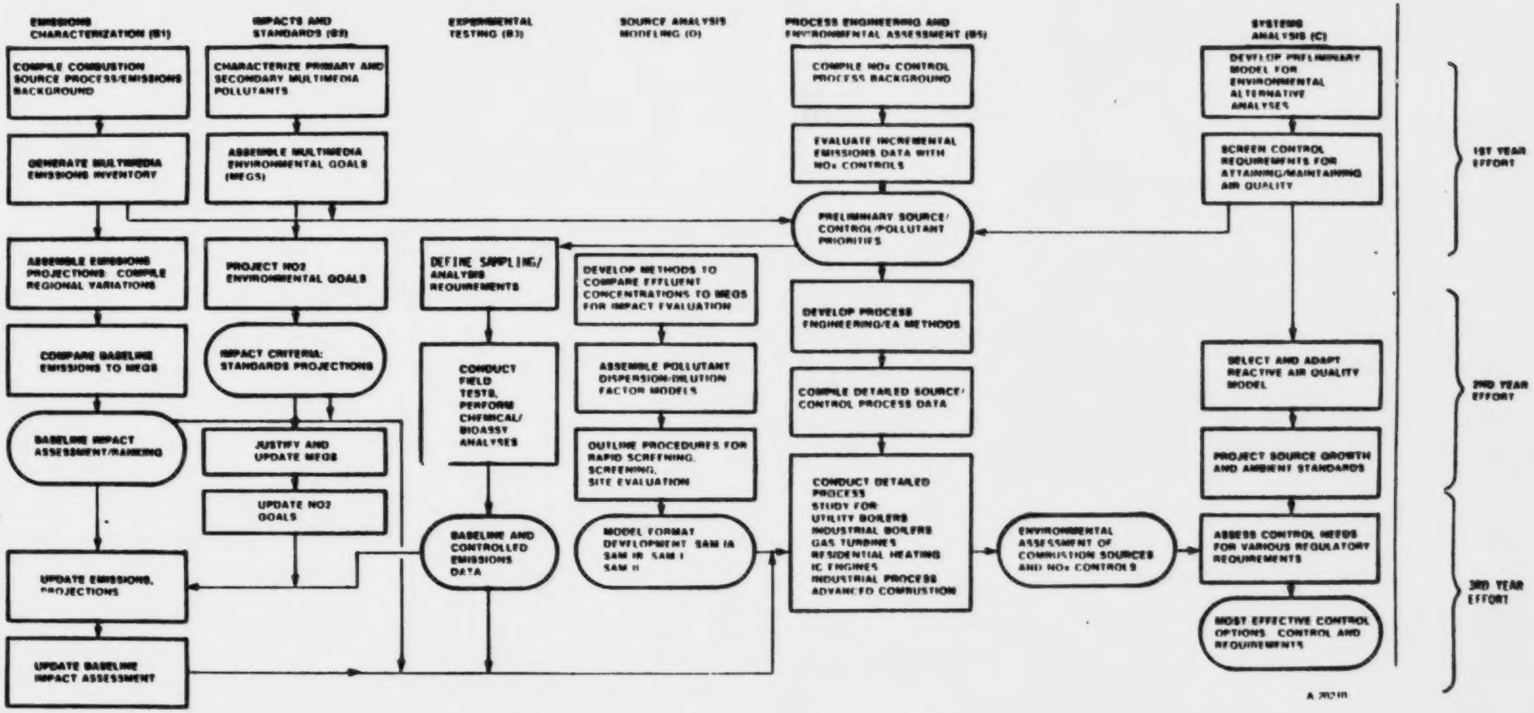
EMISSIONS CHARACTERIZATION (B1)
IMPACTS AND STANDARDS (B2)
EXPERIMENTAL TESTING (B3)
SOURCE ANALYSIS MODELING (D)
PROCESS ENGINEERING AND ENVIRONMENTAL ASSESSMENT (B5)
SYSTEMS ANALYSIS (C)
COMPILE COMBUSTION SOURCE PROCESS/EMISSIONS BACKGROUND
GENERATE MULTIMEDIA EMISSIONS INVENTORY
ASSEMBLE EMISSIONS PROJECTIONS: COMPILE REGIONAL VARIATIONS
COMPARE BASELINE EMISSIONS TO MEGS
BASELINE IMPACT ASSESSMENT/RANKING
UPDATE EMISSIONS, PROJECTIONS
UPDATE BASELINE IMPACT ASSESSMENT
CHARACTERIZE PRIMARY AND SECONDARY MULTIMEDIA POLLUTANTS
ASSEMBLE MULTIMEDIA ENVIRONMENTAL GOALS (MEGS)
PROJECT NO2 ENVIRONMENTAL GOALS
IMPACT CRITERIA: STANDARDS PROJECTIONS
JUSTIFY AND UPDATE MEGS
UPDATE NO2 GOALS
DEFINE SAMPLING/ ANALYSIS REQUIREMENTS
CONDUCT FIELD TESTS, PERFORM CHEMICAL/ BIOASSY ANALYSES
BASELINE AND CONTROLLED EMISSIONS DATA
DEVELOP METHODS TO COMPARE EFFLUENT CONCENTRATIONS TO MEGS FOR IMPACT EVALUATION
ASSEMBLE POLLUTANT DISPERSION/DILUTION FACTOR MODELS
OUTLINE PROCEDURES FOR RAPID SCREENING, SCREENING, SITE EVALUATION
MODEL FORMAT DEVELOPMENT SAM IA SAM IB SAM I SAM II
COMPILE NOx CONTROL PROCESS BACKGROUND
EVALUATE INCREMENTAL EMISSIONS DATA WITH NOx CONTROLS
PRELIMINARY SOURCE/ CONTROL/POLLUTANT PRIORITIES
DEVELOP PROCESS ENGINEERING/EA METHODS
COMPILE DETAILED SOURCE/ CONTROL PROCESS DATA
CONDUCT DETAILED PROCESS STUDY FOR: UTILITY BOILERS INDUSTRIAL BOILERS GAS TURBINES RESIDENTIAL HEATING IC ENGINES INDUSTRIAL PROCESS ADVANCED COMBUSTION
ENVIRONMENTAL ASSESSMENT OF COMBUSTION SOURCES AND NOx CONTROLS
DEVELOP PRELIMINARY MODEL FOR ENVIRONMENTAL ALTERNATIVE ANALYSES
SCREEN CONTROL REQUIREMENTS FOR ATTAINING/MAINTAINING AIR QUALITY
SELECT AND ADAPT REACTIVE AIR QUALITY MODEL
PROJECT SOURCE GROWTH AND AMBIENT STANDARDS
ASSESS CONTROL NEEDS FOR VARIOUS REGULATORY REQUIREMENTS
MOST EFFECTIVE CONTROL OPTIONS, CONTROL AND REQUIREMENTS
1ST YEAR EFFORT
2ND YEAR EFFORT
3RD YEAR EFFORT
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Figure P-1. NO_x EA approach.

and established a priority rankings based on source emission impact and potential for effective NO_x control, to be used in the current ongoing detailed evaluation.

This report presents the assessment of combustion modification NO_x controls for the third source category to be treated, gas turbines. Other environmental assessment reports documented are:

- Environmental Assessment of Utility Boiler Combustion Modification NO_x Controls (Reference P-2)
- Environmental Assessment of Industrial Boiler Combustion Modification NO_x Controls (Reference P-3)
- Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines (Reference P-4)
- Environmental Assessment of Combustion Modification Controls for Residential and Commercial Heating Systems (Reference P-5)

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SECTION 1

EXECUTIVE SUMMARY

This is the third in a series of five special reports to be documented in the "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x EA). Specifically, this report documents the environmental assessment of stationary gas turbines, with primary emphasis on NO_x combustion controls. The program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls applied to these sources, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000.

With more NO_x controls being implemented in the field and expanded control development anticipated for the future, there is currently a need to: (1) ensure that the current and emerging control techniques are technically and environmentally sound and compatible with efficient and economical operation of systems to which they are applied, and (2) ensure that the scope and timing of new control development programs are adequate to allow stationary sources of NO_x to comply with potential air quality standards. The stationary gas turbine EA helps to address these needs by evaluating the operational, economic and environmental impacts from applying combustion modification NO_x controls.

Gas turbines are the fifth largest contributors of NO_x emissions from stationary anthropogenic sources in the U.S. -- constituting a 2.0 percent share (Reference 1-1). A variety of factors including fuels, electricity demand and increasing thermal efficiencies, will tend to intensify the NO_x problem from stationary gas turbines. Given this background and their potential for NO_x control, stationary gas turbines have been selected as one of the major source categories to be treated under the NO_x EA program.

1.1 OVERVIEW OF STATIONARY GAS TURBINES

Gas turbines are rotary internal combustion engines commonly, although not universally, fired with natural gas or "clean" liquid fuels such as diesel or distillate oils. The basic gas turbine consists of a compressor, combustion chamber(s) and a turbine. Pressurized combustion air, supplied by the compressor, and fuel are burned in the combustion chambers. The hot combustion gases are rapidly quenched in the combustor by secondary dilution air and then expanded through turbines which drive the compressor and provide shaft power to, e.g., a generator, compressor, or pump.

Three different thermodynamic cycles are typically used in stationary gas turbine engines -- simple, regenerative and combined cycles. The simple cycle is the basic gas turbine engine while the regenerative and combined cycles employ some form of exhaust waste heat recovery. Throughout this report, stationary gas turbines have been divided for analysis purposes into three capacity ranges (power output):

- Large capacity, including combined cycle, ≥15 MW (20,000 hp)
- Medium capacity, 4 MW to 15 MW (5,000 to 20,000 hp)
- Small capacity, < 4 MW (5,000 hp)

Gas turbines have enjoyed spectacular sales growth through 1970 due primarily to their inherent low cost and operational and maintenance advantages over other prime movers and electrical generation types. A growing economy combined with delays in nuclear plant licensing also contributed to their popularity. With the 1970's came decreased oil availability and a growing uncertainty among users concerning the reliability of gas turbines, causing a subsequent steady decline in sales. In addition, forecasts of new generating requirements by the National Electrical Manufacturers Association (NEMA) have shown substantial reductions over previous forecasts of gas turbine equipment. Figure 1-1 shows the Sixth Biennial Survey of Power Equipment Requirements (Reference 1-2). The gas turbine generating additions predicted in 1978 have decreased 78 percent from NEMA's 1973 predictions. Although the

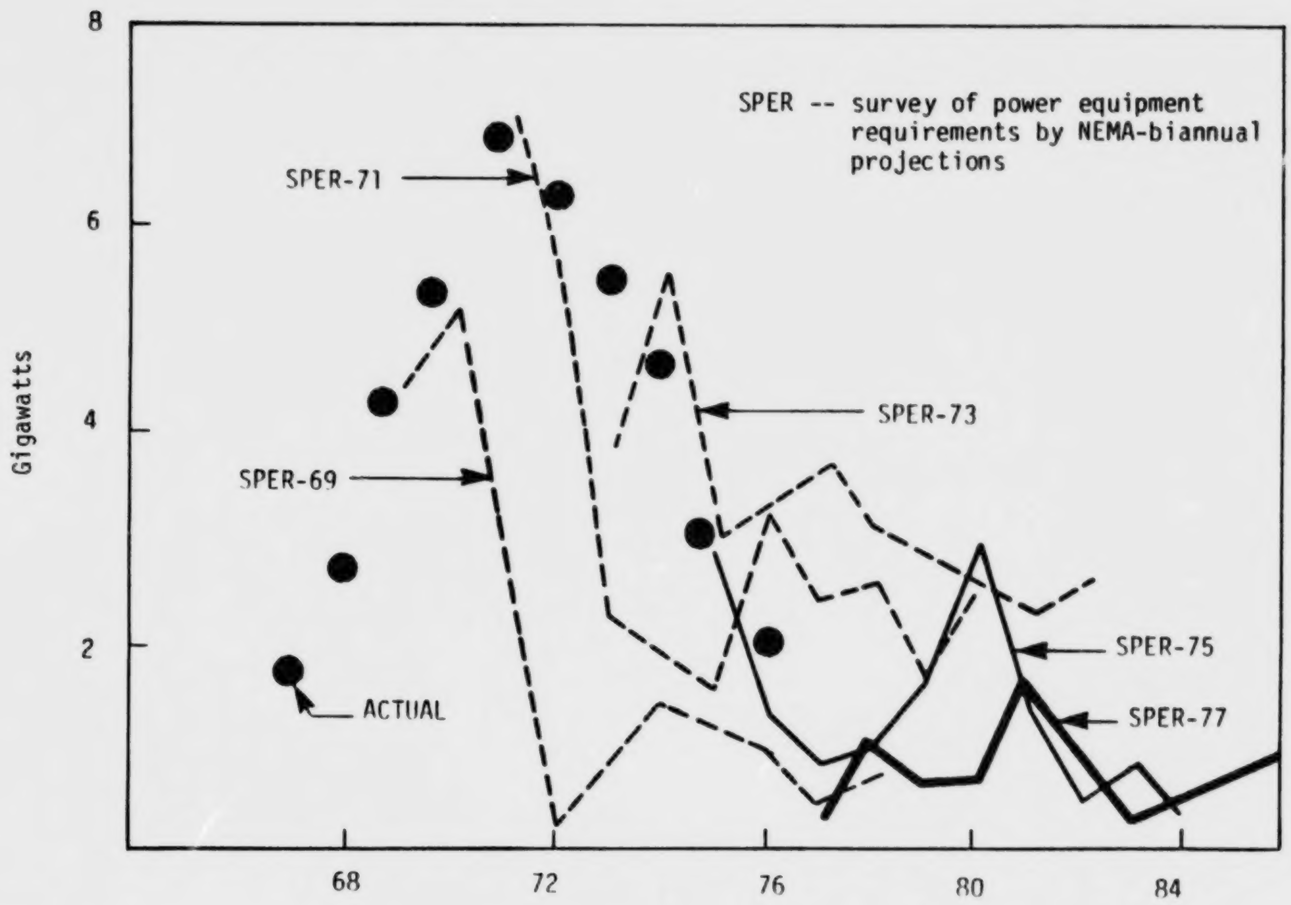

Figure 1-1. Projected gas turbine generating additions. (Reference 1-2)(Reproduced by permission of the National Electrical Manufacturers Association from the Sixth Biennial Survey of Power Equipment Requirements of the U.S. Electric Utility Industry 1977-1986, NEMA, PE-S-6-1978.)

immediate future does not look bright, manufacturers are optimistic about an upswing in the market, particularly for combined cycle plants.

1.2 EMISSIONS AND FUELS

Air emissions in the form of exhaust gases are essentially the only effluent stream from stationary gas turbines. Stream composition depends highly on the fuel burned, combustor geometry, combustion and operating characteristics. NO_x emissions are highest and CO and unburned hydrocarbons (UHC) are lowest when the engine operates at design conditions (i.e., rated power output). Off-design firing, while limiting NO_x, enhances the production of unburned species through incomplete oxidation. Virtually all fuel sulfur is converted to sulfur dioxide (SO_2) in a turbine engine, the concentration being purely a function of the fuel sulfur content. Using low sulfur fuel is the only viable means to control SO_2 emissions.

The only liquid and solid wastes from gas turbines are from the water treatment facilities associated with water injection for NO_x control. These effluent streams are relatively small, generally innocuous, and easily disposed of in landfill areas or to rivers or municipal sewers. As dry NO_x controls gradually replace wet controls, these liquid and solid discharges will no longer exist.

Natural gas and distillate oils are the preferred fuels for gas turbines because they are relatively clean burning. Those oils containing significant ash and trace element concentrations, such as crude oil, residual oil, and synthetic fuels may require some treatment before they can be used.

NO_x is one of the primary pollutants of concern with stationary gas turbines. It is emitted in relatively large quantities, is deleterious to human respiratory functions and acts as a key precursor to photochemical smog. NO_x in gas turbines, as in all combustion sources, is formed primarily by two mechanisms -- thermal fixation and fuel NO_x formation. Thermal NO_x results from the thermal fixation of molecular nitrogen and oxygen in the combustion air and the rate of formation increases exponentially with local flame temperature. Fuel NO_x results from the oxidation of organically bound nitrogen found in certain fuels such as residual oil, and primarily depends on the nitrogen content of the fuel. In general, liquid fuels yield a higher NO_x emission level than gaseous fuels. This is due primarily to higher localized flame temperatures resulting from droplet burning and, to some extent, on the amount of fuel nitrogen.

Emissions of carbon monoxide (CO) and (UHC) are related to the operating cycle and generally inversely follow load. For example, decreasing load reduces NO_x, but increases CO and UHC concentrations. Thus in all control development efforts, a balance must be maintained between NO_x and CO and UHC.

Particulate emissions from gas turbines are a function of the ash content of the fuel, and the levels of carbon and unburned hydrocarbons due to incomplete combustion. Thus, particulate emissions will increase with the use of "dirty" fuels and as combustion becomes less efficient.

1.3 STATUS OF ENVIRONMENTAL PROTECTION ALTERNATIVES

Wet controls, which inject steam or water directly into the combustion chamber, are the only currently available methods sufficiently developed to reduce gas turbine NO_x emissions below the recently promulgated (1980) NO_x New Source Performance Standard (NSPS -- 75 ppm at 15 percent oxygen for clean fuels) and more stringent local regulations. Wet controls work on the principle of thermal quenching -- effective lowering of peak flame temperatures thereby reducing NO_x generation. The required degree of control is obtained by altering the water-to-fuel ratio. However, depending on the water-to-fuel ratio and operating conditions, emissions of unburned hydrocarbons and CO may increase. Furthermore, the effectiveness of wet controls decreases significantly as the percentage of fuel-bound nitrogen in the fuel increases.

Dry NO_x controls generally refer to combustor modifications and do not involve water or steam injection. A number of general concepts are currently being examined by dry control developers, but one in particular is emerging as the most promising. The Pratt and Whitney Aircraft Group under EPA sponsorship has recently completed demonstration of a new combustor concept for stationary gas turbines known as rich burn/quick quench (RBQQ), in a full-scale engine. NO_x emissions were well below NSPS for both clean and dirty fuels, and CO was simultaneously held to low levels.

Other organizations are developing different dry control concepts with various degrees of success. Many of these programs are being conducted with meeting the aircraft jet engine emissions standards in mind, thus the designs and dry control concepts are being evaluated for aircraft engines which burn clean jet fuels. There is some disagreement as to whether this approach to dry NO_x controls will be adaptable to stationary gas turbines designed to fire a variety of fuels.

Implementing wet NO_x controls can significantly impact the total operating cost of a stationary gas turbine, which varies greatly among users. Various utilities have reported capital costs ranging from $5/kW to almost $23/kW in 1978 dollars. A typical utility gas turbine will cost, in total, approximately $150/kW in 1978 dollars. Actual costs are very site specific and depend to a great extent on the required water purification equipment and to a lesser extent on turbine modifications. Also, a fuel penalty resulting from an increased heat rate with water injection is a significant portion of this increased expense. The total annualized cost of wet controls, including capital and operating costs, raises the cost of electricity by about 2 to 5 percent.

At this stage of development of dry controls, it is difficult to accurately predict their associated costs. Whether development costs are passed on to the user and the market size over which these costs can be spread, will be major factors in determining the magnitude of dry control costs. It appears that dry NO_x controls which have development expenditures included in their total cost will cost somewhat less than wet NO_x controls for a comparably sized unit. If development costs are not passed on, dry control combustors are expected to be only nominally more costly than existing combustor models.

In summary, wet controls are currently the preferred, indeed the only commercially demonstrated, NO_x control techniques which meet the NO_x NSPS for stationary gas turbines. Although the capital costs of water injection can be significant, approximately 10 percent of total unit cost on a per kW basis, annualizing that cost along with operating costs over the lifetime of the unit results in an incremental cost of electricity of only 2 to 5 percent.

Dry controls, as they become fully developed for full size engines, will begin to replace wet controls in new sources. They appear to be more attractive from virtually all standpoints, including economics. Catalytic combustion, while yielding extremely high pollutant reductions in subscale models, is only feasible for production engines in the very long term.

1.4 DATA NEEDS AND RECOMMENDATIONS

A substantial amount of good quality data regarding wet control emissions reduction was collected by EPA for use in the Standard Support and Environmental Impact Statement (SSEIS -- Reference 1-3). Results from additional emissions testing programs since the completion of the SSEIS have been added to the data base. These data support the general trends reported in the SSEIS regarding NO_x emission reductions and the relationships between percent NO_x reduction and water-to-fuel ratio.

A significant amount of disparity was found in both capital and operating cost estimates for wet controls from users, manufacturers, and the EPA. Other than for large scale gas turbines where a few users could supply actual costs, data in this report are primarily manufacturer and EPA cost estimates. Even for large scale units, data were sparse since most users are not yet required to control NO_x.

Given the existing state of development of dry NO_x controls, it is not possible to perform a comprehensive environmental analysis. This report relies heavily on experimental combustor program literature and some industry contacts to qualitatively assess the postulated effects of the most promising dry control concepts. Since much of the developmental work is proprietary, the information presented is incomplete. Furthermore, the work conducted so far has generally been performed on a single combustor rig. Significant research and development will be required before these dry control concepts can be reliably applied to actual engines.

The available data for all dry NO_x control techniques only provide qualitative judgements and estimates when predicting costs, incremental emissions, and operations and maintenance impacts. In assessing this report's evaluation, it should be noted that dry controls are an emerging technology and are at least two to four years from the first full scale application. Numerous changes in the preferred design, which could have a major impact on the predicted environmental effects, may occur.

As users and manufacturers gain experience, additional emissions data should be gathered and periodically evaluated during the life cycle of existing, modified and new stationary gas turbines. This is necessary because dry NO_x control techniques are just evolving as a technology and there is a considerable lack of long term operating experience with wet controls.

Specific areas where opinions differ regarding impacts due to wet controls include:

- Water injection cost data for capital equipment, operating and maintenance expenses
- The cost/benefit ratio of wet controls for small gas turbines (<4 MW) (Note: small engines have a 5 year exemption from NSPS to develop dry controls)
- Quantification of the fuel penalty due to increased heat rate and, additional power output resulting from more mass throughput.

At present, it seems clear that dry NO_x controls will be the preferred control technology option for new gas turbines within 5 years. However, because they are still in the development stage, very little actual data exist regarding emission levels, control costs and operations and maintenance impacts for the application of dry controls to full scale engines. All of these data are required to perform a meaningful environmental assessment of dry NO_x control technology. As the direction of dry controls research becomes evident, additional testing programs can be suitably designed to provide the proper data base. Then, as dry controls become commercially feasible and users gain operating experience, any additional data gaps may be filled accordingly. The types of gaps will primarily be additional operating and maintenance costs that can only be accurately predicted through long term expense accounting. Only with long term experience, as well as careful front-end tracking of dry control developments, can a comprehensive environmental assessment be performed. The task should not be extremely complicated for gas turbines. Dry controls do not require as much ancillary equipment as do wet controls, so in this regard, they can be considered less complex. Also, most manufacturers expect no additional costs over wet controls, nor do they expect any significant operational or maintenance impacts.

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SECTION 2

INTRODUCTION

This report assesses the operational, economic, and environmental impacts from applying combustion modification NO_x controls to stationary gas turbines. With more NO_x controls being implemented in the field and expanded control development anticipated for the future, there is currently a need to: (1) ensure that the current and emerging control techniques are technically and environmentally sound, and compatible with efficient and economical operation of systems to which they are applied, and (2) ensure that the scope and timing of new control development programs are adequate to allow stationary sources of NO_x to comply with potential air quality standards. The NO_x EA program addresses these needs by (1) identifying the incremental multimedia environmental impact of combustion modification controls, and (2) identifying the most cost-effective source/control combinations to achieve ambient NO_2 standards.

2.1 BACKGROUND

The 1970 Clean Air Act Amendments designated oxides of nitrogen (NO_x) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. Accordingly, in 1971, EPA set a primary and secondary National Ambient Air Quality Standard (NAAQS) for NO_2 of 100 $\mu g/m^3$ (annual average). To attain and maintain the standard, the Clean Air Act mandated control of new mobile and stationary NO_x sources, each of which currently emits approximately half of the manmade NO_x nationwide. Emissions from light duty vehicles (the most significant mobile source) were to be reduced by 90 percent to a level of 0.25 g NO_2/km (0.4 g/mile) by 1976. Stationary sources were to be regulated by EPA's New Source Performance Standards

(NSPS), which are set as control technology becomes available. Additional standards required to attain air quality in the Air Quality Control Regions (AQCRs) could be set for new or existing sources through the State Implementation Plans (SIPs).

Since the Clean Air Act, techniques have been developed and implemented that reduce NO_x emissions by a moderate amount (30 to 60 percent) for a variety of source/fuel combinations. In 1971, EPA set NSPS for large steam generators burning gas, oil, and coal (except lignite). Recently, more stringent standards for utility boilers burning all gaseous liquid and solid fuels have been promulgated. In addition, NSPS have been promulgated for stationary gas turbines and are currently being considered for stationary internal combustion engines and intermediate size (industrial) steam generators. Local standards also have been set, primarily for new and existing large steam generators and gas turbines, as parts of State Implementation Plans in several areas with NO_x problems. This regulatory activity has resulted in reducing NO_x emissions from individual stationary sources by 30 to 60 percent. The number of controlled sources is increasing as new units are installed with factory equipped NO_x controls.

Emissions have been reduced comparably for light duty vehicles. Although the goal of 90 percent reduction (0.25 g NO_2/km) by 1976 has not been achieved, emissions were reduced by about 25 percent (1.9 g/km) for the 1974 to 1976 model years and in 1979 were reduced to 50 percent to 1.25 g/km. Achieving the 0.25 g/km goal has been deferred indefinitely because of technical difficulties and fuel penalties. Initially, the 1974 Energy Supply and Environmental Coordination Act deferred compliance to 1978. Recently, the Clean Air Act Amendments of 1977 abolished the 0.25 g/km goal and replaced it with an emission level of 0.62 g/km (1 g/mile) for the 1981 model year and beyond. However, the EPA Administrator is required to review the 0.25 g/km goal, considering the cost and technical capabilities as well as the need of such a standard to protect public health or welfare. A report to the Congress is due July 1980.

Because the mobile source emission regulations have been relaxed, stationary source NO_x control has become more important for maintaining air quality. Several air quality planning studies have evaluated the need for stationary source NO_x control in the 1980's and 1990's in view of recent developments (References 2-1 through 2-9). These studies all conclude that relaxing mobile standards, coupled with the continuing growth rate of stationary sources, will require more stringent stationary source controls than current and impending NSPS provide. This conclusion has been reinforced by projected increases in the use of coal in stationary sources. The studies also conclude that the most cost-effective way to achieve these reductions is by using combustion modification NO_x controls in new sources.

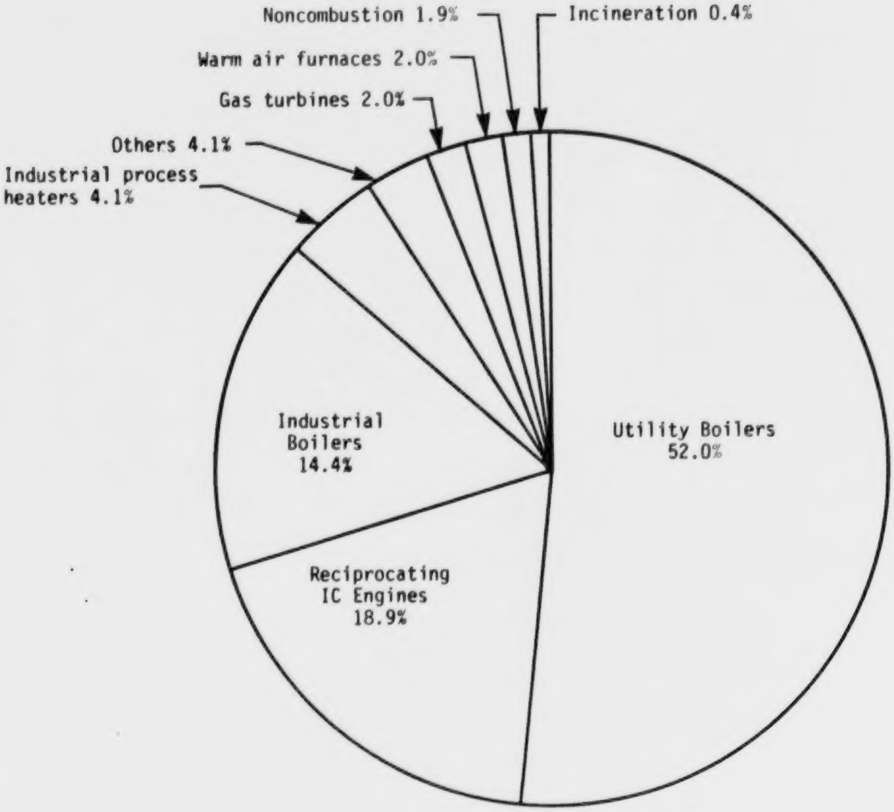
It is also possible that separate NO_x control requirements will be needed to attain and/or maintain additional NO_2 related standards. Recent data on the health effects of NO_2 suggest that the current NAAQS should be supplemented by limiting short term exposure (References 2-4 and 2-10 through 2-12). In fact, the Clean Air Act Amendments of 1977 require EPA to set a short term NO_2 standard for a period not to exceed 3 hours unless it can be shown that such a standard is not needed. EPA will probably propose a short term standard in 1980 when update of the NO_2 air quality criteria document (Reference 2-13) is completed (References 2-14 and 2-15).

EPA is continuing to evaluate the long range need for additional NO_x regulation as part of strategies to control oxidants or pollutants for which NO_x is a precursor, e.g., nitrates and nitrosamines (References 2-4, 2-10, and 2-14 through 2-17). These regulations could be source emission controls or additional ambient air quality standards. In either case, additional stationary source control technology could be required to assure compliance.

In summary, since the Clean Air Act, near term trends in NO_x control are toward reducing stationary source emissions by a moderate amount, hardware modifications in existing units or new units of conventional design will be stressed. For the far term, air quality projections show that more stringent controls than originally anticipated will be needed. To meet these standards, the preferred approach is to control new sources by using low NO_x redesigns.

2.2 ROLE OF GAS TURBINES

Stationary gas turbines are the fifth largest contributor of NO_x emissions in the U.S. Figure 2-1 shows that 2.0 percent (on a weight



Total: 10.5 Tg/yr (11.6 x 10^6 tons/yr)

Figure 2-1. Distribution of stationary anthropogenic NO_x emissions for the year 1977 (controlled NO_x levels) (Reference 2-18).

basis) of all NO_x emissions from stationary sources in 1977 were from stationary gas turbines (Reference 2-18).

In that year, gas turbines consumed approximately 1.1 EJ or approximately 2 percent of the total U.S. energy use of about 48 EJ (Reference 2-18). With electricity demand continuing to increase and manufacturers constantly striving to improve thermal efficiency in their units (which generally favors increased NO_x production), NO_x emissions from stationary gas turbines will continue to be a problem unless adequate controls are developed. The problem may be aggravated when the current trend to burn "clean" fuels is reversed and fuels such as residual oils and synthetic fuels, which show a propensity for higher NO_x formation, become the fuels of choice. In addition, the proposed National Energy Plan will encourage research and development aimed at substituting coal and coal-derived fuels for natural gas and petroleum products (Reference 2-19). The implications for gas turbines involve increased pollution potential from use of synthetic coal liquids and gases.

Given this background and their potential NO_x control, stationary gas turbines were selected as the third source category to be treated under the NO_x EA program. The "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference 2-8) concluded that modifying combustion process conditions is the most effective and widely used technique for achieving 20 to 70 percent reduction in oxides of nitrogen. Nearly all current NO_x control applications use combustion modifications. Other approaches, such as treating postcombustion flue gas, are being evaluated in depth in other programs (Reference 2-20) for potential future use.

2.3 OBJECTIVE OF THIS REPORT

This report provides comprehensive, objective, and realistic evaluations and comparisons of the important aspects of the available combustion NO_x control techniques, using a common and uniform basis for comparison. The objective is to perform an environmental assessment of NO_x combustion modification techniques for stationary gas turbines to:

- Determine their impact on the achievement of selected environmental goals, based on a comprehensive analysis from a multimedia consideration

- Ascertain the effect of their application on turbine performance and identify potential problem areas
- Estimate the economics of their operation
- Estimate the limits of control achievable by combustion modification
- Identify further research and development and/or testing required to optimize combustion modification techniques and to upgrade their assessments

2.4 ORGANIZATION OF THIS REPORT

Evaluating the effectiveness and impacts of NO_x combustion controls applied to stationary gas turbines requires assessing their effects on both controlled source performance, especially as translated into changes in operating costs and energy consumption, and on incremental emissions of other pollutants as well as NO_x. To perform such an evaluation, it is necessary to:

- Characterize the source category with regard to equipment, fuels, emissions, and incremental costs (Section 3)
- Identify NO_x formation mechanisms and relate fuels to their emissions potential (Section 4)
- Evaluate the performance of current and developing NO_x control techniques through examination of NO_x and incremental emissions under controlled conditions (Section 5)
- Estimate the capital and operating costs, including energy impacts of implementing NO_x control (Section 5)
- Evaluate the environmental impact of NO_x controls through the analysis of incremental emissions (Section 6)
- Assess the total impact of NO_x controls on ambient air, economics, energy and operations and maintenance of the turbine, thereby evaluating the effectiveness of current and emerging control technology (Section 6)

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SECTION 3

SOURCE CHARACTERIZATION

This section presents a general characterization of gas turbines as a stationary air pollutant source to aid in understanding subsequent sections of this report. Unlike some sources, such as utility boilers, which are categorized by many equipment types, each requiring individual analysis, gas turbines are distinguished more by size categories. Consequently much of the distinction in analysis within the following sections is by categories defined according to rated power output. This approach is consistent with the Preliminary Environmental Assessment of Combustion Modification Techniques (Reference 3-1) and the Standard Support and Environmental Impact Statement for stationary gas turbines (Reference 3-2).

Simple and combined-cycle turbines offer the greatest potential for NO_x control with dry combustion controls (the preferred NO_x control technique for the 1980s), especially considering that regenerative cycle turbines are decreasing in popularity due to their limited efficiency and slowness in getting up to power. Large capacity gas turbines are treated as a separate group. The classification includes both large industrial engines and the large aircraft derivative engines. This is a valid grouping with respect to NO_x control technology because both types exhibit similar combustor volume constraints with retrofit low-NO_x combustors. Due to a relatively large population, medium capacity gas turbines are also treated separately. Since the application and distribution of small capacity gas turbines may present localized NO_x problems, they too will be treated separately. These divisions also facilitate the economic impact assessment of NO_x controls.

Fuel requirements and use played a key role in defining the focus of this report. The primary fuels for gas turbines are the clean fuels -- natural gas and distillate oils. The dirtier fuels, such as residual oils, can be fired in suitably equipped gas turbines. But their use can cause additional operational and maintenance problems, as well as increased emissions of NO_x and SO_x. Their use, however, is slowly becoming more attractive as clean fuels escalate in cost and become less available. For similar reasons, synthetic coal-derived fuels are also approaching the point where they are becoming a viable gas turbine fuel.

The remainder of this section presents an overview of the gas turbine industry and discusses technical aspects such as load use, cycle types and efficiencies, and capital and operating cost considerations.

3.1 TECHNICAL OVERVIEW OF GAS TURBINES

This subsection presents a broad overview of gas turbines, leaving specific details on equipment and cycle types to the next subsection. Detailed process descriptions can be found in Section 3.2. Topics included here are an overview of developments and trends in the industry, brief discussions of applications, fuels, emissions, energy efficiencies, and costs.

Throughout this report, stationary gas turbines are typically divided into three capacity ranges:

- Large capacity, including combined cycle, $\geq$15 MW (20,000 hp)
- Medium capacity, 4 MW to 15 MW (5,000 to 20,000 hp)
- Small capacity, < 4 MW (5,000 hp)

3.1.1 Status of Development

The growth of gas turbines as prime movers since the early 1960s to early 1970s has been exceptional. There are numerous reasons for this acceptance, but among the more important are the following gas turbine characteristics:

- Ability to operate on a variety of fuels
- Short delivery times
- Fast response to load changes
- Quiet, reliable operation
- Capability for remote operation
- High power to size ratio

Also, much of the spectacular rise in gas turbine generating additions shown in Figure 3-1 has been due to a shortage of generating capacity caused by delays in nuclear licensing and by the growth in the economy during the late 60's and early 70's (Reference 3-3). On a unit basis growth has not been as spectacular, even decreasing in 1968 and 1971. This reflects the fact that most sales have been to electric utilities, who primarily use large capacity units and that gas transmission sales have steadily declined in the United States (Reference 3-2).

Figure 3-1 shows a steady decline in gas turbine generating additions throughout the early and mid-1970s, primarily because the fuel availability situation changed dramatically in this time period. Fuel price increases (including natural gas) had a particularly detrimental effect on the appeal of gas turbines, which tend to be less efficient engines than diesels, for example. The capital cost advantage of gas turbines was offset by the fuel penalty. Also, availability of clean fuels to the utility industry was questionable, further contributing to the sales decline.

The domestic gas turbine market is dominated by a few large companies. In fact, the three largest, General Electric Company, Turbo Power and Marine, and Westinghouse, control 80 percent of the market. Also within capacity groups, certain companies dominate the market. For example, Solar Turbines International of International Harvester, Airesearch Manufacturing Company, and Detroit-Diesel Allison Division of General Motors control a major share of the small capacity turbine market while G.E., Westinghouse and Turbo Power and Marine control much of the medium and large capacity sectors. Much of the new information in this report was derived from these manufacturers, as well as users of their models.

3.1.2 The Future for Gas Turbines

The Sixth Biennial Survey of Power Equipment Requirements (SPER) sponsored by the National Electrical Manufacturers Association (NEMA) shows substantial reductions in forecasts of new generating additions over 1973 projections (Reference 3-3). Gas turbine installations have decreased 78 percent from SPER-1973 projections as shown in Figure 3-2. The forecasted generating additions for all types of generation are shown in Table 3-1. Gas turbines hold an average of 2.3 percent of the total

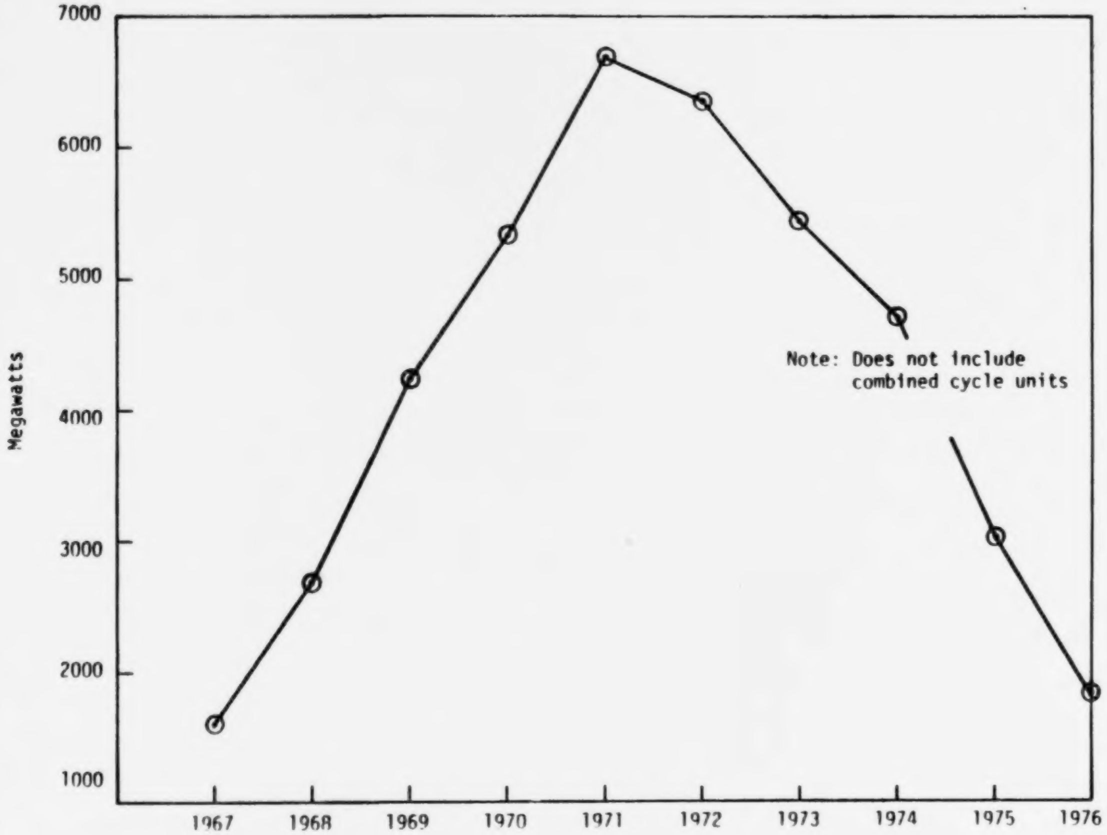

Figure 3-1. Gas turbine generating additions (Reference 3-3). (Reproduced by permission of the National Electrical Manufacturers Association from the Sixth Biennial Survey of Power Equipment Requirements of the U.S. Electric Utility Industry 1977-1986, NEMA, PE-S-6-1978.)

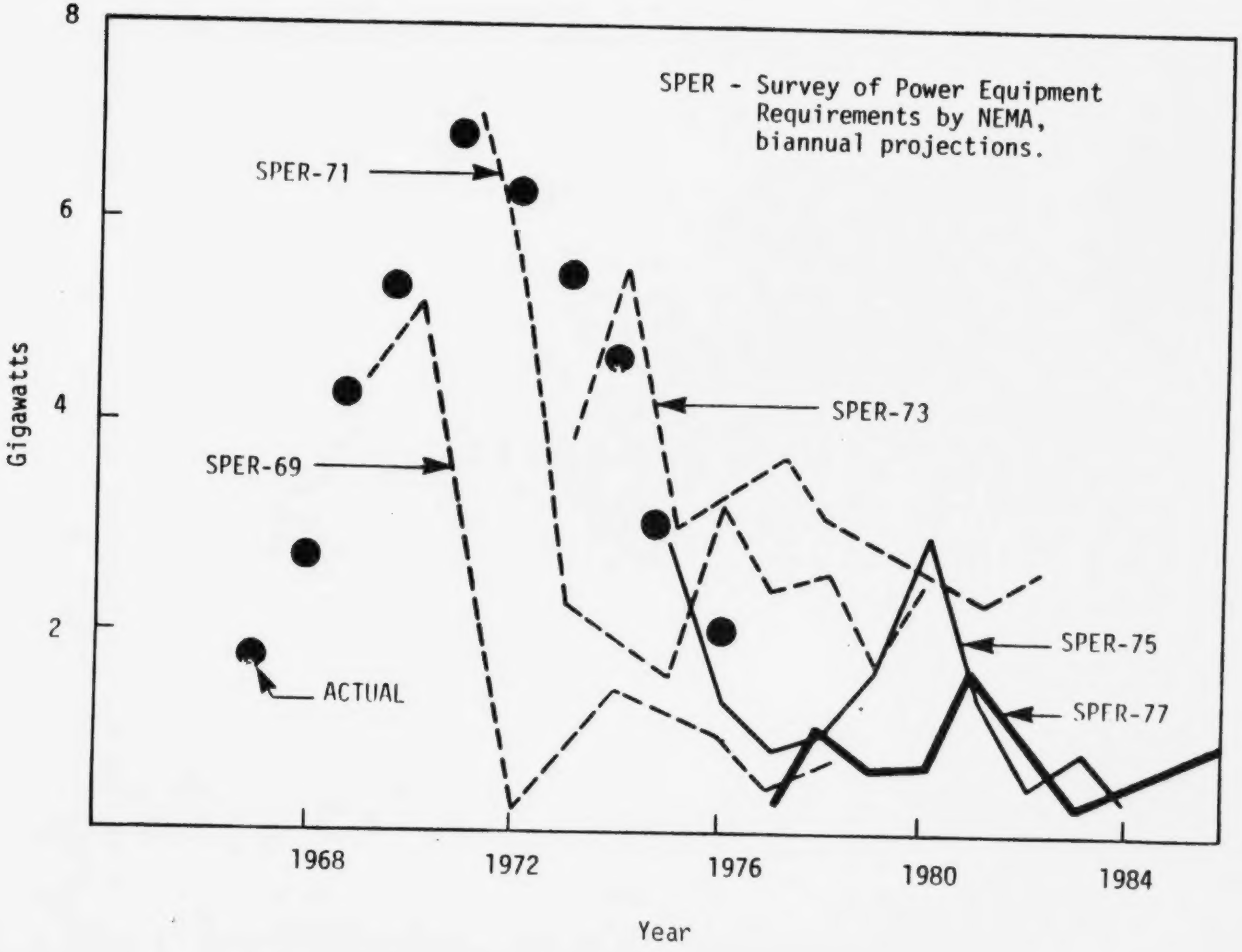

Figure 3-2. Projected gas turbine generating additions (Reference 3-3). (Reproduced by permission of the National Electrical Manufacturers Association from the Sixth Biennial Survey of Power Equipment Requirements of the U.S. Electric Utility Industry 1977-1986, NEMA, PE-S-6-1978.)

TABLE 3-1. FORECASTED GENERATING ADDITIONS FOR ALL GENERATOR TYPES THROUGH 1986 (Reference 3-3)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Fossil Steam	18,278	15,389	14,155	19,670	13,015	12,633	15,856	14,895	16,731	16,982
Nuclear	7,165	7,705	9,169	10,284	12,154	15,031	15,599	21,848	11,940	16,911
Conventional Hydro	392	1,783	1,609	668	309	456	808	130	660	140
Pumped Storage Hydro	550	1,813	234	345	1,254	503	2,776	800	425	672
Gas Turbine	404	1,087	621	700	1,452	850	217	438	593	866
Combined Cycle	1,158	613	0	1,095	349	430	766	439	1,948	736
Total Additions	27,947	28,390	25,788	32,762	28,533	29,903	36,022	38,550	32,297	36,307

Generation additions in megawatts.
Gas Turbine category includes a small number of diesel units, statistically insignificant.

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generating additions through 1986. This value will most certainly increase for certain locations which favor gas turbines. Utilities are currently planning only limited generating additions through the use of gas turbines. However, under certain circumstances utilities may again accelerate their orders of gas turbines. For example, if nuclear and fossil fuel plants are experiencing long delays in a time of high peak energy needs, whether for licensing or construction reasons, a shortfall in electrical generating capacity will develop. Gas turbines would then be in the best position to provide that capacity.

The outlook for the gas turbine industry in the immediate future (1 to 2 years) does not look bright according to some industry sources (References 3-4 and 3-5). Domestic sales in particular are in a depressed state for a variety of reasons. Fears of an economic recession are one cause while fuels availability and pricing situation are also significant factors. Prices currently tend to favor diesel IC engines rather than the less fuel efficient gas turbine. The future outlook, however, is optimistic for a reversal in this trend. Apparently utilities have put to use nearly all the excess capacity available and most of the easy and convenient energy conservation measures have been implemented. Consequently utilities may soon be looking to expand their capacity. Gas turbine sales may also increase once combustors become commercially available that can burn high nitrogen fuels and still meet NSPS.

The outlook for combined cycle plants is particularly bright for the industry. A 1975 Survey of U.S. Electric Utilities (Reference 3-6) shows that almost 60 percent of the respondents favored combined cycle for future generation. A recent study by General Electric Corporate Research and Development also looks toward combined cycle plants for long range capacity (Reference 3-7). Of 21 advanced energy conversion cycles studied for their technical and economic promise for use from 1985 to 2000, various combined cycles realized the lowest busbar energy costs. Whether it was an air cooled engine firing low Btu gas, a water cooled engine firing low Btu gas, or a water cooled engine firing semiclean fuel, gas turbine combined cycles were consistently among the two most economic cycles for base, midrange and peak power modes. In addition, the high thermal efficiencies of combined cycle gas turbine plants makes the future look brighter, particularly with regards to the use of synthetic fuels.

3.1.3 Load Use

The reasons cited in Section 3.1.1 for the popularity of gas turbines also reflect their flexibility. The primary use of large gas turbines is in peak load electric-generating use. Indeed, over 90 percent of gas turbine capacity sold in the U.S. now goes to electrical utilities, and this percentage is continuing to increase (Reference 3-1). Under certain circumstances, large simple cycle machines are favored for base load uses. Combined cycles are favored by utilities for intermediate and base load applications due to their high efficiencies and fuel flexibility. The second largest user of large stationary gas turbines is the gas and oil industry, where gas turbines are ideal due to their variety of sizes and ability to run remotely and unattended for long periods. Additional uses include stand-by power, private electric generation and additional industrial purposes requiring shaft power.

Taken on a size category basis, the primary load uses are as follows:

Category	Load Use
Large capacity	• Primarily base, midrange and peak utility electrical generation
Medium capacity	• Electrical standby generation
	• Pipeline compression and pumping
	• Industrial electrical generation
	• Variety of industrial uses requiring shaft power
Small capacity	• Standby electric generation for the oil and gas industry
	• Gas compression

3.1.4 Fuels and Emissions

Stationary gas turbines primarily utilize clean fuels, typically natural gas and distillate oils. The oil shortage of the early 1970s, however, had a profound effect on the fuel situation. The whole question of fuels availability has become very volatile and difficult to predict. The industry is now being forced to examine options regarding what fuels will be available when current supplies of clean fuels are expended or become unavailable due to regulation. Already some utilities are firing residual oils, although, due to the high cost of pretreating residual oils, the economics generally favor gas or distillate oils. Still, Westinghouse reports considerable success with residual oil, with one of their units running 2000 hours.

Some of the reported problems when firing dirtier fuels include coking on fuel nozzles and clogging fuel filters. Typically some degree of preliminary treatment is required, such as reducing sodium by 50 percent and using an additive to inhibit vanadium corrosion. In these cases manufacturers report no problems with "hot" components (i.e., those equipment parts in contact with combustion gases) (Reference 3-8). In some cases the turbine inlet temperature would have to be lowered to prevent sulfidation if sulfur is present in the fuel. This, however, may have a detrimental effect on cycle efficiency.

Some of the most promising new clean fuels are low and high Btu gases and process gases such as coke oven and blast furnace gases (Reference 3-9). Improved thermodynamic cycle efficiencies and low NO_x emissions make these clean fuels attractive alternatives in broadening basic energy sources. There are, however, a number of redesign considerations with the use of certain low Btu fuels in conventional engines. Modifications to the combustion and fuel systems are all that is required with some fuels. But with others, significant problems arise from a compressor-turbine mismatch due to inordinately high pressure ratios caused by excessive turbine weight flow. A more comprehensive discussion of gas turbine fuel alternatives is given in Section 4.1.

According to the Emission Characterization of Stationary NO_x Sources (Reference 3-10) which cites fuel consumption data for stationary gas turbines, the 1974 estimates are of high quality. The total energy consumed by gas turbines was about 3.5 percent of the total stationary source fuel consumption in 1974. As Table 3-2 shows, medium-capacity units consumed more fuel than the large units. The bulk of the fuel consumption of these medium-capacity turbines was either in the oil and gas industry, where equipment operates almost constantly, or in private sector electricity generation, where equipment operates about three-quarters of the time.

TABLE 3-2. 1974 GAS TURBINE FUEL CONSUMPTION (EJ)

Gas Turbines	Natural Gas	Oil[a]	Total
Gas Turbines $\geq$15 MW	0.212	0.264	0.476
Gas Turbines 4 MW to 15 MW	0.468	0.579	1.047
Gas Turbines <4 MW	0.001	0.001	0.002

[a] Includes distillate, diesel, residual oils

Similarly, regional fuel consumption data are of high quality, particularly that from the utility sector. Additional data were traced through manufacturers. In general, distillate oil shows a strong domination in the New England and Middle Atlantic regions while the West-North-Central, East-North-Central, Mountain and Pacific regions are primarily serviced by natural gas.

Air emissions are essentially the only effluent stream from stationary gas turbines. The stream composition is highly dependent on the fuel burned, combustor geometry and combustion characteristics. NO_x emissions are highest and CO and UHC are lowest when the engine is operating at design conditions (i.e., rated power output). Off-design firing, while limiting NO_x, enhances the production of unburned species through incomplete oxidation. One method to enhance combustion of these unburned species is to increase residence time through enlargement of the reaction zone of the combustor. This is particularly applicable with today's combustors and lean primary zone burning. Virtually all the fuel sulfur is converted to sulfur dioxide in a turbine engine, the concentration being purely a function of the fuel sulfur content. Selecting fuels low in sulfur is the only means to control SO_x emissions. Flue gas desulfurization, when applied to gas turbines, is overwhelmingly expensive (Reference 3-2).

The only liquid waste associated with gas turbines is from the water treatment equipment in a NO_x control water injection system. The waste water flowrate, when compared to that from a comparably sized utility steam boiler, is small and after pH treatment, is relatively innocuous. Typical disposal techniques involve evaporation, return to rivers or municipal sewers. Once dry NO_x controls become commercially available (1982 by most estimates), water wastes will no longer exist.

Wastes from water treatment evaporation ponds are the only solid effluent from gas turbines. Again, these wastes are relatively innocuous and easily disposed of as landfill. With the advent of dry controls, this waste problem will also be obviated.

3.1.5 Capital and Operating Costs

This section describes the types of considerations involved in evaluating the total costs associated with stationary gas turbines equipped with some form of NO_x control. Capital costs include purchasing and installing the required equipment. For wet controls, the cost includes the water purification system, water injection system, and any additional turbine modifications. For dry controls the cost would be for engine modifications. Fixed costs per year, taken as 20 percent of installed costs, would include such factors as depreciation, taxes, insurance, etc. Operating and maintenance costs are taken to be 3 to 5 percent of installed costs, depending on size and use of the turbine. We consider operating and maintenance costs to include labor to operate the control device and normal maintenance. Any maintenance cost to the gas turbine resulting from the control device is in addition to the normal operating and maintenance costs. The cost of any additional fuel usage caused by the NO_x control device and, in the case of wet controls, water costs, must also be considered in assessing total costs of owning and operating a stationary gas turbine with NO_x controls.

3.2 PROCESS DESCRIPTION

Gas turbines are rotary internal combustion engines commonly, although not universally, fired with natural gas or "clean" liquid fuels such as diesel or distillate oils. The simple cycle gas turbine shown in Figure 3-3 is a Brayton cycle engine consisting of adiabatic compression, constant-pressure heating and adiabatic expansion processes. While this cycle type predominates the stationary gas turbine population, there are

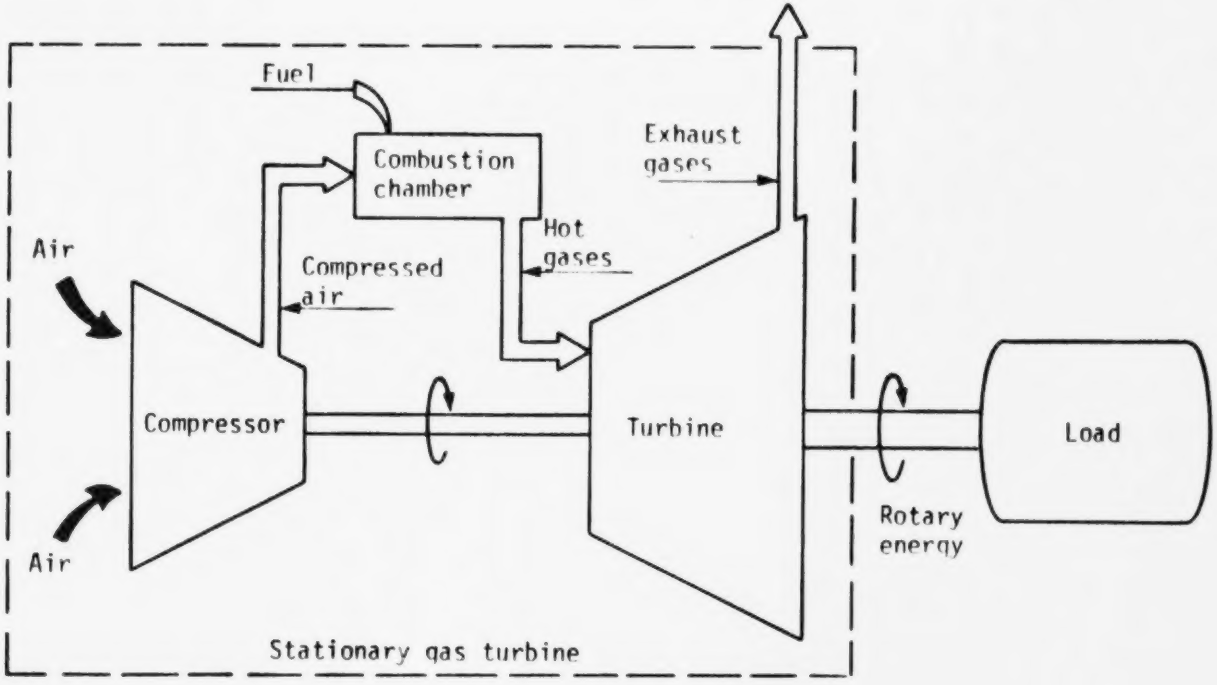
Fuel
Combustion chamber
Exhaust gases
Hot gases
Air
Compressed air
Compressor
Turbine
Load
Air
Rotary energy
Stationary gas turbine

Figure 3-3. Basic simple cycle gas turbine.

two other types in common use: the regenerative cycle and the combined cycle shown in Figures 3-4 and 3-5. Both cycles recover waste exhaust heat to improve thermal efficiency. The regenerative cycle uses turbine exhaust to heat incoming combustion air while the combined cycle uses turbine exhaust gases to produce steam in a waste heat boiler. The product steam then can be used to power a steam turbine or to provide process steam.

Gas turbines can range in size from 40 hp to over 75 MW (100,000 hp) and are commonly installed in groups by utilities to obtain more power output. Such an arrangement may involve single turbines with their own generators or multiple turbines connected to one generator.

The basic gas turbine consists of a compressor, combustion chambers and a turbine. The compressor delivers pressurized air to the combustors at compression ratios of up to 20 to 1. Injectors introduce fuel into the combustors. The hot combustion gases are rapidly quenched by secondary dilution air, reducing gas temperatures to 1,370 K (2,000^{o}F), before being expanded through the turbine. The turbine drives the compressor and provides shaft power to a generator, compressor, pump, etc.

These basic components can be arranged in a variety of ways. On some engines the combustor is placed axially between the compressor and the turbine. In this design, the combustor may be made up of a series of individual "cans" encircling the drive shaft or of two concentric cylinders mounted to produce a single annular combustion chamber (hence the terms cannular and annular combustor designs). On other gas turbines, the combustor is a single large volume chamber, connected to the compressor and turbine by ducting, but not necessarily physically located between the compressor and the turbine. A typical simple cycle gas turbine may be a dual spool engine with can-annular combustors and a free power turbine. The engine is dual spool because the high and low pressure compressors each have independent rotor systems driven by independent compressor turbines. The power turbine is free because it is not connected to either compressor rotor. Other engines may simply have a single shaft connecting the compressors, compressor turbine and power turbine.

Manufacturers are continually seeking ways to improve cycle efficiency, usually through cycle variations or through increased

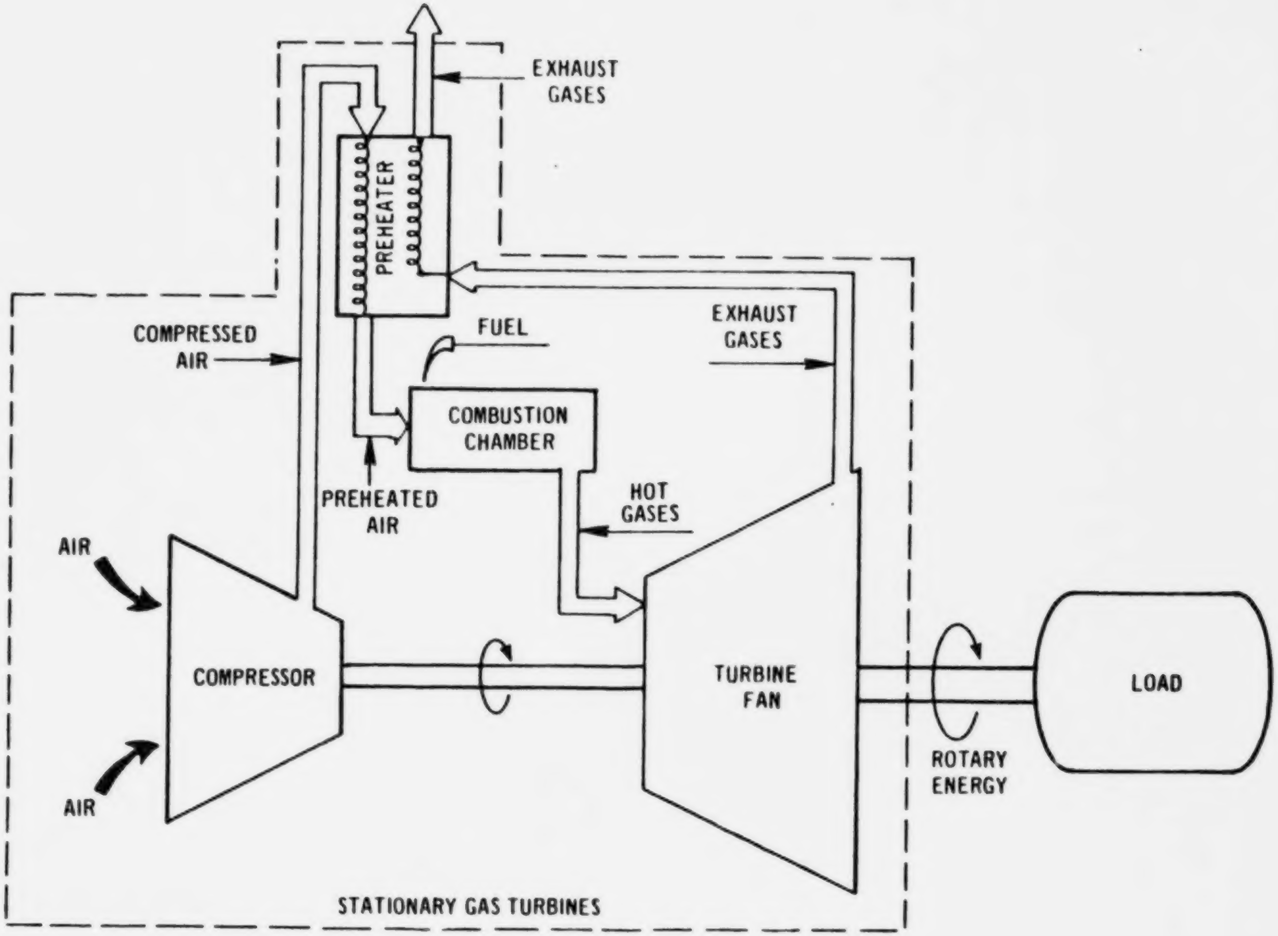
EXHAUST
GASES
PREHEATER
COMPRESSED
AIR
FUEL
EXHAUST
GASES
COMBUSTION
CHAMBER
PREHEATED
AIR
HOT
GASES
AIR
AIR
COMPRESSOR
TURBINE
FAN
LOAD
ROTARY
ENERGY
STATIONARY GAS TURBINES

Figure 3-4. Typical regenerative cycle gas turbine.

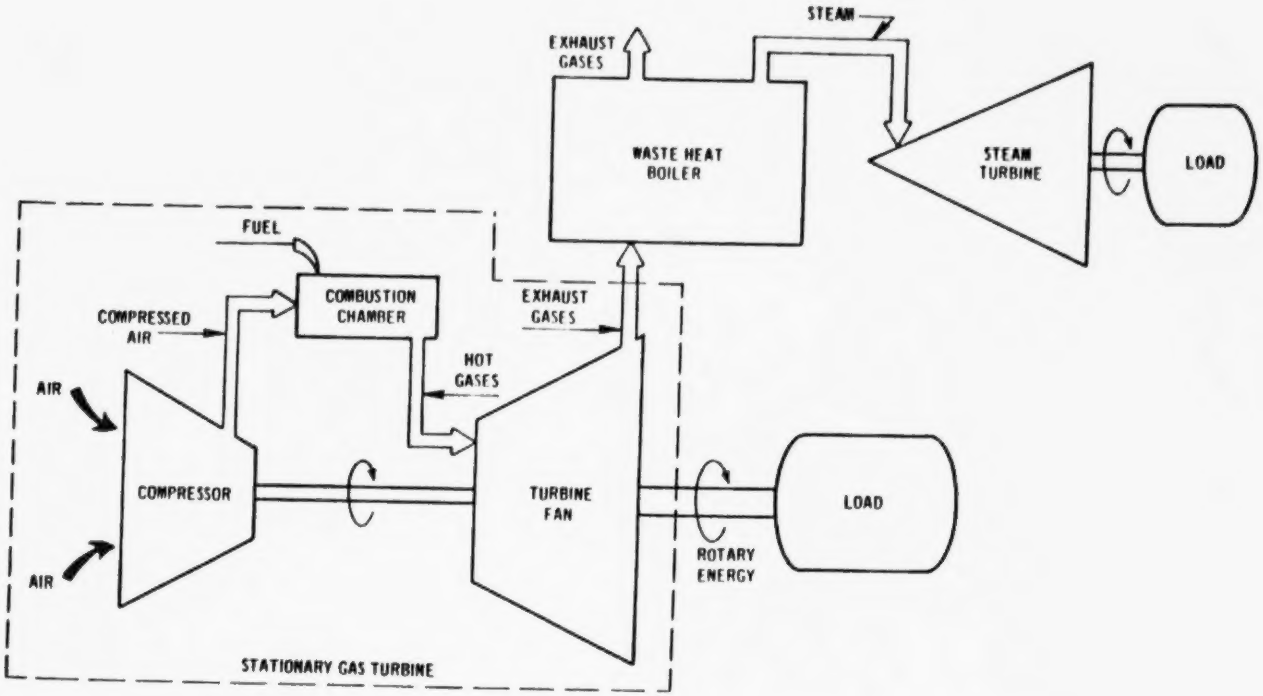
EXHAUST GASES
STEAM
WASTE HEAT BOILER
STEAM TURBINE
LOAD
FUEL
COMBUSTION CHAMBER
COMPRESSED AIR
EXHAUST GASES
HOT GASES
AIR
AIR
COMPRESSOR
TURBINE FAN
LOAD
ROTARY ENERGY
STATIONARY GAS TURBINE

Figure 3-5. Typical combined cycle gas turbine.

compression ratios and turbine inlet temperatures. Very significant gains in system thermal efficiency can be achieved by recovering thermal energy in the turbine exhaust. The regenerative air heater (recuperator) employs this "waste" thermal energy to preheat incoming combustion air (already compressed). In effect, this requires less heat (in the form of fuel) to be added to meet the design gas conditions entering the turbine. Figure 3-6 shows typical efficiency curves for different pressure ratios for regenerative and simple cycle gas turbines at a specific turbine inlet temperature. The figure shows that regenerators are beneficial only over a limited pressure ratio. In high compression ratio machines, the compressed air is already substantially heated. Consequently it is not feasible to transfer heat from exhaust gases which are only slightly warmer than the compressed air.

Combined cycle plants recover "waste" thermal energy from the gas turbine exhaust by using this heat to generate steam in a waste heat boiler. Occasionally additional steam is generated by supplementary fuel firing in the waste heat boiler. Due to their superior overall system efficiencies, 44 to 47 percent versus 36 to 38 percent for a conventional steam boiler, and their potential for even higher efficiencies, combined cycle systems are one of the most promising alternative powerplant designs for base and intermediate load service. This is particularly true now that coal-derived synthetic fuels are becoming more economically viable.

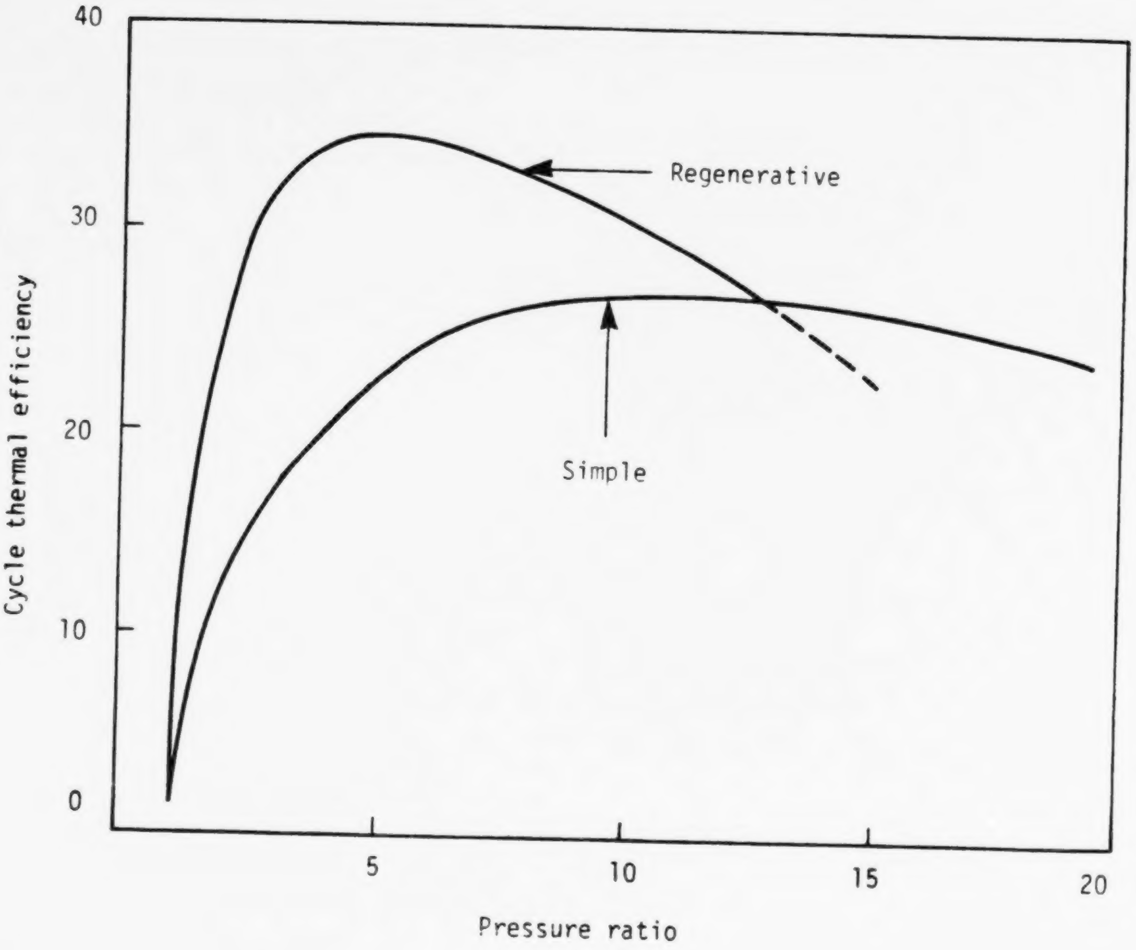

Figure 3-6. Comparison of efficiency vs. pressure ratio for simple and regenerative cycle engines.

REFERENCES FOR SECTION 3

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SECTION 4

CHARACTERIZATION OF INPUT MATERIALS, PRODUCTS, AND WASTE STREAMS

This section summarizes the physical and chemical characteristics of input materials (fuels), products (shaft power and waste heat), and waste streams (primarily gaseous emissions). The focus of this section will, however, be on fuel properties since they are a dominant factor in determining the type and quantity of emissions.

4.1 INPUT MATERIALS

The basic input materials to a gas turbine are fuel and combustion air. In addition, if the gas turbine has wet NO_x controls, steam or water may also be input. The emphasis in this section is on fuels, gas and liquid. Discussion of associated contaminants that may be entrained with the combustion air or steam/water is incorporated within the appropriate fuel subsections.

The basic design of gas turbines tends to limit the fuels of combustion to the "clean" fuels, natural gas and distillate oils. Those oils which contain significant ash and trace element concentrations, such as crude and residual oils, may require some treatment before they can be used. Coal and some liquids are used to synthesize low Btu gases. These gases will find increased use due to the reduced availability of the standard gas turbine fuels (References 4-1 and 4-2). Also, coal and shale derived liquids are showing promise as gas turbine fuels.

4.1.1 Gas Fuels

Natural gas is one of the primary fuels used in gas turbines. It can be used directly from the distribution center if the solid contents from such contaminants as water, sand, rust, naphthalene and others are less than 30 ppm (Reference 4-3). Greater impurity contents may require some fuel pretreatment. The lessened availability of natural gas will lead to increased use of other fuels (References 4-1 and 4-2). Table 4-1 summarizes the typical properties of some common gaseous fuels (Reference 4-4).

One of the most promising new fuels is low Btu gas, produced by air injected coal or oil gasifiers, or other chemical processes. This fuel, although promising, has emissions and operating problems of significantly greater magnitude than those associated with natural gas.

The low Btu gas composition from a gasifier depends on its configuration and operating conditions. Typically, as shown in Table 4-2, the combustible constituents of the gas are hydrogen, carbon monoxide, and some methane. Natural gas is presented as a reference (Reference 4-1). Ammonia (NH_3), sometimes present in product gases, may be converted to NO in lean flames, possibly with yields of greater than 50 percent (Reference 4-1). Future NO_x emission standards for gas turbines may require engine manufacturers who wish to use low Btu fuels to establish specific limits on the amount of NH_3 allowable in the fuel gas or to use combustors designed to fire high NH_3 fuels and still meet NSPS. Similarly, H_2S limits will be dictated by environmental concerns rather than manufacturer requirements. Any H_2S present will form SO_2 when burned.

Two parameters of the combustion of low Btu fuels which affect turbine design (modification) and emissions are the stoichiometric fuel-to-air ratio and the stoichiometric temperature rise. The fuel-to-air ratios for low Btu fuels are considerably greater than those of natural gas (Reference 4-1). The stoichiometric ratio for natural gas is typically 0.062 Fuel/Air (F/A) whereas with low Btu fuel, it may approach 0.712 (F/A) on a volume basis. This is approximately an order of magnitude increase in the gaseous flow into the primary combustion chamber (Reference 4-2). The increase in fuel flow requires larger control valves, nozzles, and possibly primary combustion zones. (Reference 4-2). But, primarily, a switch to low Btu fuels would cause a significant redesign of engine controls due to a combustor/turbine mismatch. It follows, then, that changes in input fuels to a machine must be carefully considered.

The maximum flame temperature (i.e., stoichiometric temperature rise) is a function of the fuel composition. For many of the low Btu

TABLE 4-1. TYPICAL PROPERTIES OF COMMON GASEOUS FUELS (Reference 4-4)

Property	Natural Gas (Dry)	Coal Gas (Low Btu)	Coal Gas (High Btu)	Coke Oven Gas	Blast Furnace Gas
Heating Value, Btu/ft^3	950/1150	110/165	500/700	525/650	90/100
Heating Value, Kcal/m^3	8400/10,200	1000/1500	4500/6200	4500/6200	700/800
Specific Gravity	0.58/0.72	0.80/0.92	0.41/0.48	0.40/0.45	0.95/1.05
Composition, Volume %					
Methane, CH_4	75/97	0.5/4.5	20/35	28/32	--
Hydrogen, H_2	2/20	--	2/4	2/4	--
Carbon Monoxide, CO	--	2/32	5/15	5/7	25/30
Nitrogen, N_2	1/16	30/55	4/11	1/6	55/60
Carbon Dioxide, CO_2	0.1	0.5/10	2/4	2/3	8/16

EE-T-010

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TABLE 4-2. TYPICAL ANALYSIS AND PROPERTIES FOR LOW Btu GASEOUS FUELS (Reference 4-1)

	Natural Gas	Lurgi[b]	Fluidized Bed[b] Coal Gas	BOM. 7644[b]	Winkler #1[b]	Winkler #2[b]	Producer Gas From Coal	Blast Furnace Gas	Blue Water Gas	Coal Gas (Vertical Retort w/Steaming)
Analysis (% by volume)										
O_2	--	--	--	--	--	--	--	--	--	0.4
N_2	.5	30.2	50.4	54.5	55.3	1	52.4	60	4.5	6.2
CO_2	1.8	10.7	.5	7.2	10	19	4	11	4.7	4
CO	--	10.7	31.8	2.0	22	38	29	27	41	18
H_2	--	15.4	15.6	15.5	12	40	12	2	49	49.4
CH_4	93.3	4.4	.5	2.8	0.7	2	2.6	--	0.8	20
C_2H_6	3.49	--	--	--	--	--	--	--	--	2
C_3H_8	0.68	--	--	--	--	--	--	--	--	--
C_4H_{10}	0.18	--	--	--	--	--	--	--	--	--
C_5H_{12}	0.04	--	--	--	--	--	--	--	--	--
H_2O	--	27.8	.5	--	--	--	--	--	--	--
H_2S	--	0.5	.7	--	--	--	--	--	--	--
Specific Gravity	0.600	0.772	0.827	0.856	0.912	0.705	0.871	1.010	0.550	0.475
(f/a)stoic										
(by wt)	0.062	0.712	0.674	0.770	1.040	0.344	0.711	1.462	.248	0.120
(by vol)	0.103	0.923	0.815	0.899	1.141	0.488	0.817	1.448	0.450	0.252
LHV										
(Btu/scf)	930	121	154	132	110	250	150	92.3	274	422
(Btu/lbm)	20,255	2041	2429	2021	1578	4641	2250	1194	6504	11,626
HHV										
(Btu/scf)	1030	150	163	143	117	272	158	93.3	299	471
(Btu/lbm)	22,441	2488	2569	2182	1674	5049	2379	1207	7105	12,965

[a] For reference purposes only, not a low Btu gas.

[b] Gas from various types of coal gasification schemes (see Reference 4-3).

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fuels, the lower heating value results in lower maximum flame temperatures (Reference 4-2). Since the rate of NO_x formation increases exponentially with local flame temperature when firing clean fuels, lower NO_x emissions will result (References 4-1, 4-2, 4-5).

Another priority pollutant emitted from the combustion of low Btu fuel is carbon monoxide (CO). CO has the slowest combustion rate of any species found in the combustion flames of typical hydrocarbon fuels (Reference 4-1). Therefore, for new engines burning low Btu fuels the residence time must be increased in the primary combustion zone (over that of an existing engine).

Other contaminants which could be emitted in the flue gas are trace elements which can enter the system independent of the fuel. These are primarily sodium and potassium, conceivably entering through the compressor inlet air, particularly in ocean environments; injected water or steam; or evaporative cooler carryover. Some trace elements such as those in salt water may also be entrained in the fuel. These elements can react with sulfur, forming sodium sulfate (for example), which is a corrosive compound at high temperatures. These corrosive compounds can be controlled by limiting the amounts of trace elements entering the combustion zone in the air/water/steam/fuel.

4.1.2 Liquid Fuels

As previously mentioned, existing engines have been designed to be fired with clean fuels. In the case of oils, distillates are preferred. Recent indications are that future trends, dictated by fuel availability and economics, may be towards heavier residual oils.

Table 4-3 summarizes the specifications of the various grades of oils. Those physical and chemical properties that will affect turbine operation and emissions are discussed below. In general, true distillates may be fired as received and at normal climatic conditions, while ash-bearing fuels may require some pretreatment. So called synthetic fuels, such as the middle and heavy distillates obtained from pyrolysis of coal, are also becoming a potential gas turbine fuel. Indeed, synthetic fuels may be the future fuel for gas turbines due to the changing market for more conventional fuels, Federal fuel use regulations, and other considerations.

TABLE 4-3. DETAILED SPECIFICATIONS FOR FUEL OILS (Reference 4-6)

Grade	Flash Point °C (°F)	Pour Point °C (°F)	Water and Sediment Volume %	Carbon Residue on 10% Bottoms, %	Ash, Weight %	Distillation Temperature °C (°F) 10%	90%		Saybolt Viscosity Universal at 38°C (100°F)		Sulfur %
	Min	Max	Max	Max	Max	Max	Min	Max	Min	Max	Max
No. 1	38 (100)	0	trace	0.15		215 (420)		288 (550)			0.5
No. 2	38 (100)	-7 (20)	0.10	0.35			286 (540)	338 (640)	(32.6)[a]	(37.4)[a]	0.7
No. 4	55 (130)	-7 (20)	0.50		0.10				45	125	no limit
No. 5 (light)	55 (130)		1.00		0.10				150	300	no limit
No. 5 (heavy)	55		1.00		0.10				350	750	no limit
No. 6	65		2.00						(900)[a]	(9000)[a]	no limit

[a] Number given for information only; not necessarily limiting.

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4.1.2.1 Physical Properties

Contaminant concentrations and viscosity are among the primary physical properties that affect operation (Reference 4-4). The fuel must be free of foreign material that would foul accessories and decrease the useful life of components. This includes water, sediment and filterable dirt. Complete precombustion particulate removal for particles larger than 5 μm is recommended by at least one equipment vendor (Reference 4-4). Sediment and other particulates can cause plugging and erosion problems with the equipment.

The quantity of water found in oil varies significantly. In light oils, such as No. 2, water is present in negligible quantities, unless it is introduced by outside contamination such as tank leakage, condensation, etc. Water can cause sparking and spitting of the flame, as well as flash- back of the flame. Loss of flame is also possible if excess water is present.

Viscosity is directly related to the atomization potential of the oil. If the fuel is not properly atomized, combustion may not be complete. The completeness of combustion, in turn, directly affects the emission levels of hydrocarbons, carbon monoxide and NO_x. Typically, as combustion efficiency goes down, unburned hydrocarbon emissions increase while NO_x decreases. Turbines firing light distillate oils generally use direct pressure or low-pressure air atomizing fuel nozzles and require preheating only during abnormally low ambient temperatures. Most heavy distillates and blends, and virtually all crude and residual oils require preheating between 320 K and 400 K (120 and 260°F), use high-pressure air atomizing fuel nozzles (Reference 4-4), and may cause a significant cost impact due to a larger compressor requirement.

4.1.2.2 Chemical Properties

Certain constituents (impurities) present in most fuel oils are noncombustible and form residual ash. Most ash found in fuel oil comes from contaminants present in crude oil, with a minor fraction due to contamination occurring during handling or refining. Heavier fuels typically contain the most ash.

The composition of fuels, particularly residual oils, may include trace elements. The five elements of prime concern are vanadium, sodium, potassium, lead, and calcium. The first three can lead to accelerated corrosion of turbine blades in elevated temperature gas turbines especially when sulfur is present. In addition, all five may cause hard deposits on the blades which can lead to reduced machine output. Table 4-4 presents ranges of the elemental analysis (excluding combustibles) of the fuel oils of interest.

Trace metals can also be introduced into the combustion system through the compressor and steam/water injection system. Sulfur from the fuel, in combination with these trace elements, particularly sodium and potassium, can combine to form compounds such as sodium sulfate and other compounds which are extremely corrosive at elevated temperatures. Generally it is best to prevent this type of corrosion, called sulfidation, by removing the contaminant in the incoming stream by giving special attention to inlet air filtration, steam/water quality, and fuel handling and treatment processes. Also turbine inlet temperatures can be kept low to prevent sulfidation. Improved turbine inlet pattern factors will also help to prevent high temperature corrosion by eliminating hot spots.

4.1.2.3 Fuel Treatment

Depending on the physical properties and the contamination level of the fuel, most ash-bearing fuels will require some degree of treatment. Fuel treating systems are generally divided into two stages: oil-desalting and additive treatment.

The oil-desalting stage is a water washing stage where the water soluble salts of sodium, potassium, and calcium are removed. The water and soluble trace elements are separated from the fuel by centrifuging or electrostatic precipitation processes.

The second stage is designed to alter the form of oil-soluble trace elements, such as vanadium. The additive found most effective in reducing vanadium corrosion is magnesium. When added in concentrations of 3:1, magnesium to vanadium, the effect is a corresponding increase in the melting point temperature of the ash and a coating effect of the thin ash deposits that form on turbine blades (References 4-4, 4-8). The deposits which collect on the mechanisms are significantly less corrosive and easily removed during turbine outages. Figure 4-1 shows the treatment process.

Sulfur removal processes such as hydrodesulfurization are also available for the heavier oils. In hydrodesulfurization, sulfur compounds

TABLE 4-4. SELECTED FUEL CONSTITUENTS (References 4-4 and 4-7)

Fuel Type / Fuel Constituent	True Distillates		Ash-Bearing Fuels		Trace Element Limitations[a]
	Kerosine	No. 2 Distillate	Blended Residuals and Crudes	Heavy Residuals	
Sulfur, %	0.01/0.1	0.1/0.8	0.2/3	0.5/4	
Nitrogen, %	0.002/0.01	0.005/0.06	0.06/0.2	0.05/0.9	
Hydrogen, %	12.8/14.5	12.2/13.2	12.0/13.2	10/12.5	
Ash (fuel as delivered), ppm	1/5	2/50	25/200	100/1000	
Ash (inhibited), ppm	--	--	25/250	100/7000	
Trace metal contaminants, untreated					
Sodium plus potassium, ppm	0/0.5	0/1	1/100	1/350	150 ppm
Vanadium, ppm	0/0.1	0/0.1	0.1/80	5/400	Legal[b]
Lead, ppm	0/0.5	0/1	0/1	0/25	1 ppm
Calcium, ppm	0/1	0/2	0/10	0/50	10 ppm

[a] Limits recommended by manufacturer (Reference 4-8)

[b] Vanadium levels less than 0.5 ppm do not require inhibition. Maximum vanadium levels are usually dictated by local codes regarding resulting stack emissions and the user's acceptable costs to inhibit. Maximum values for gas turbines are not significant; however, 400 ppm is generally slated as an upper limit.

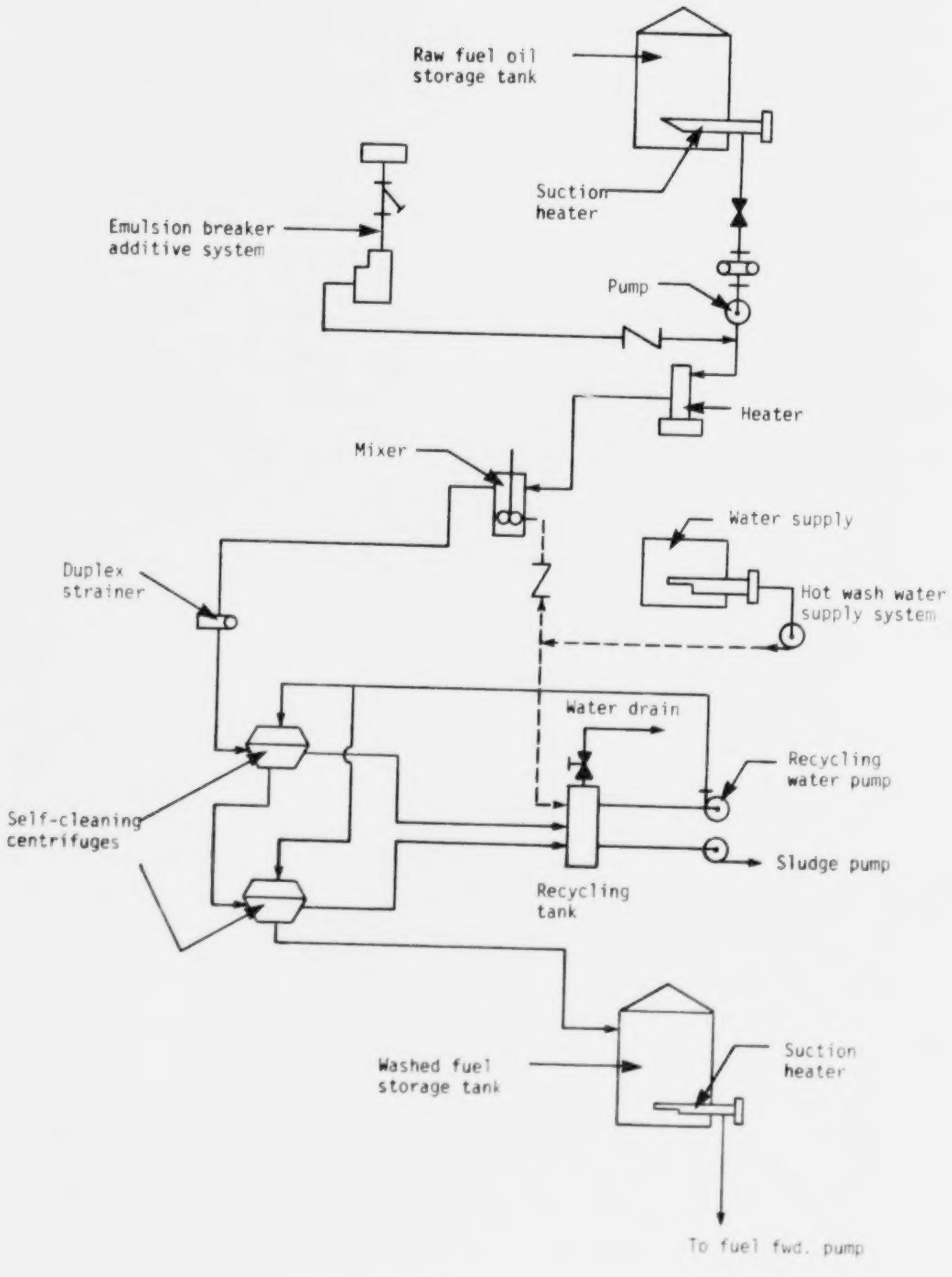
Raw fuel oil storage tank
Suction heater
Emulsion breaker additive system
Pump
Heater
Mixer
Water supply
Hot wash water supply system
Duplex strainer
Water drain
Recycling water pump
Self-cleaning centrifuges
Sludge pump
Recycling tank
Washed fuel storage tank
Suction heater
To fuel fwd. pump

Figure 4-1. Ash bearing fuels treatment (Reference 4-3). (Reproduced witn permission of Power Engineering.)

are reduced with hydrogen over a catalyst into hydrogen sulfide and hydrocarbon remnants of the original sulfur compounds. This process is performed at relatively high temperature and pressure (Reference 4-10). Hydrodesulfurization is carried out by the oil refiner and not the user. Other processes are available and are discussed in subsequent sections.

It should be noted that the treatment systems generate waste streams: liquid streams containing dissolved solids which must be disposed of in an acceptable manner, as well as gaseous emissions such as hydrogen sulfide. Furthermore, increased fuel handling and processing also increases the potential for fugitive air emissions, particularly unburned hydrocarbons. Therefore the treatment systems themselves require careful control.

4.2 NO_x Formation

Two mechanisms have been identified as responsible for NO_x formation during the combustion process: thermal NO_x formation and fuel NO_x formation.

4.2.1 Thermal NO_x Formation

Thermal NO_x results from the thermal fixation of molecular nitrogen and oxygen in the combustion air. Its formation is extremely sensitive to local flame temperature, residence time at this local flame temperature, and somewhat less so to local concentration of oxygen. Virtually all thermal NO_x is formed at the region of the flame which is at the highest temperature. This kinetically controlled behavior means that thermal NO_x emissions are dominated by local combustion conditions. The great majority of fuels used in existing engine designs are very low in fuel nitrogen. Consequently virtually all NO_x emissions are due to thermal NO_x formation.

4.2.2 Fuel NO_x Formation

Fuel NO_x derives from the oxidation of the organically bound nitrogen present in certain fuels such as residual and distillate oils. Fuel NO_x emissions are dependent on the nitrogen content of the fuel as well as on combustion conditions. Fuel NO_x formation is strongly affected by the local oxygen concentration under which combustion takes place.

Figure 4-2 shows experimental results from a bench-scale combustor indicating that fractional conversion of fuel nitrogen decreases with increasing fuel nitrogen content (up to one percent fuel nitrogen)

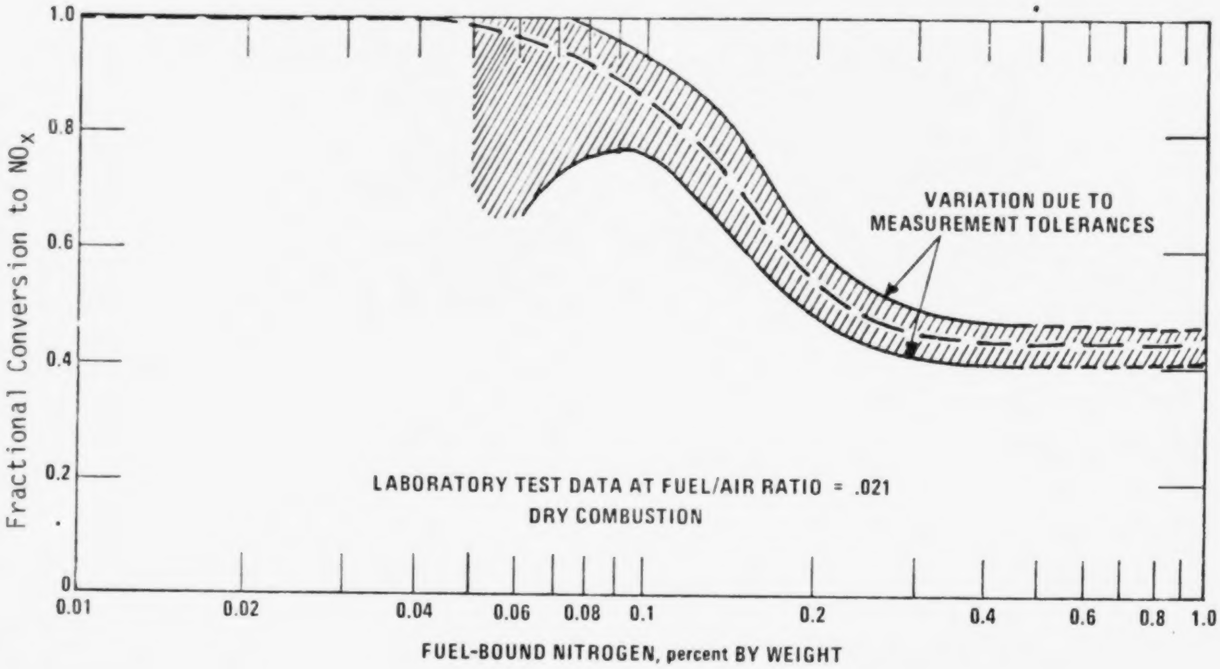

Figure 4-2. Conversion of fuel bound nitrogen to NO_x in a combustor (Reference 4-10).

(Reference 4-10). For distillate fuels, with nitrogen contents generally less than 0.015 weight percent, nearly all the fuel nitrogen is converted. But fuel NO_x is not a problem (compared to thermal NO_x) with distillate oils because of their low nitrogen content. With residual oils, however, fuel nitrogen concentrations are generally above 0.2 percent and can go as high as 2 percent (Reference 4-10). Fortunately, only a fraction of that fuel nitrogen is ultimately converted to NO_x. Figure 4-2 predicts a 40 to 50 percent conversion and data by Dilmore (Reference 4-11) indicate only a 20 to 30 percent conversion. However, actual total NO_x concentrations may increase significantly due to the high fuel nitrogen content. More recent data from EPRI and Westinghouse (Reference 4-12) indicate that the percentage of total NO_x conversion actually increases linearly, within a 20 to 50 percent range, with the weight percent of fuel bound nitrogen.

4.2.3 Fuel Potential for NO_x Production

The amount of NO_x produced is a function not only of the fuel, but also of the mechanical configuration and operation of the gas turbine. In general, for a given fuel, time, temperature and mixing considerations will dictate the quantity of NO_x in the effluent gas.

The rate of NO_x formation increases markedly with local flame temperature. Figure 4-3 shows the exponential increase in NO_x emissions with combustor inlet temperature. The same temperature dependence can be seen in Figure 4-4 (Reference 4-14), which also shows the effect of stoichiometry on NO_x formation in or near the primary reaction zone of a flame from a burner. Figures 4-5 and 4-6 show temperature and NO_x concentrations respectively as a function of position within a laboratory scale gas combustor burning liquid normal heptane. Note that as the equivalence ratios, ϕ, are increased, (where ϕ = (fuel/air)actual/(fuel/air)stoichiometric), so does the area of the hot zone. The maximum temperature does not increase but the size of the region at these highest temperatures does increase. This is partially due to there being less diluent air. The formation of NO_x in the hottest regions of the combustion zone is known as thermal NO_x and has been represented by the Zeldovich reactions combining nitrogen and oxygen in the combustion air (Reference 4-16). Note in comparing Figures 4-5 and 4-6 the correspondence of higher NO_x at higher temperatures.

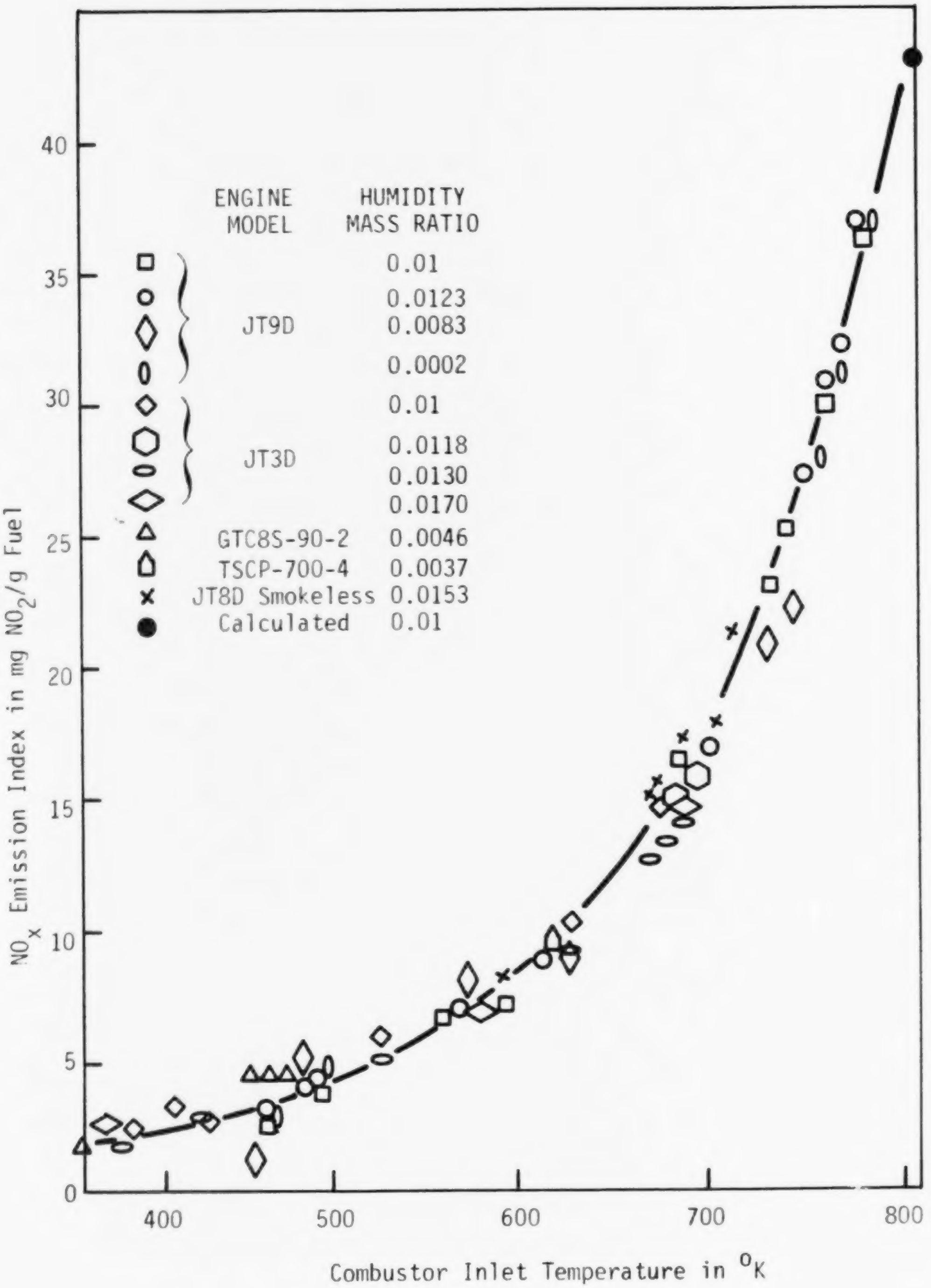

Figure 4-3. NO$_x$ emissions as a function of combustor inlet temperature (Reference 4-13). (Reproduced by permission of the ASME.)

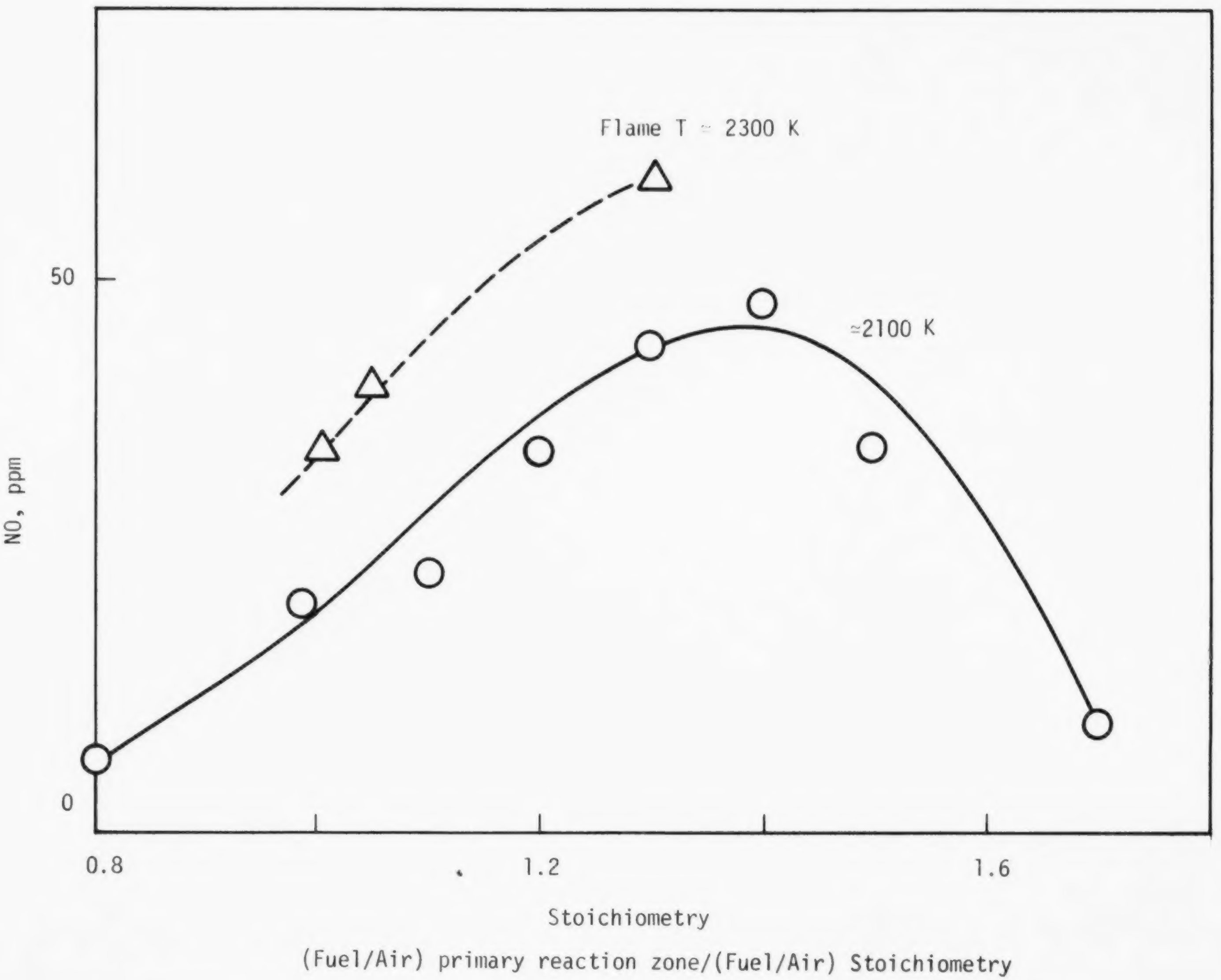

Figure 4-4. NO formed in or very near the primary reaction zone of ethylene flames (Reference 4-14).

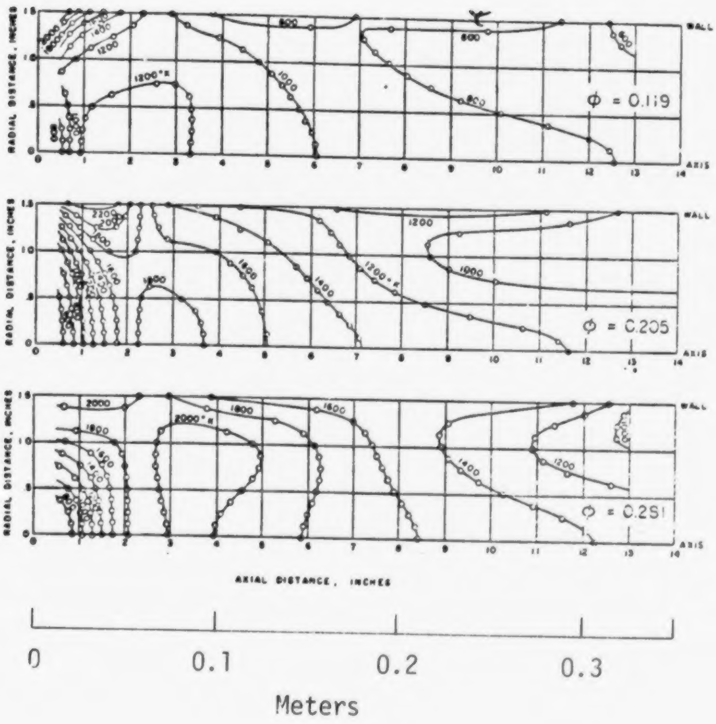

Figure 4-5. Temperature distribution maps of a laboratory scale gas combustor (Reference 4-15). (Reproduced by permission of the ASME.)

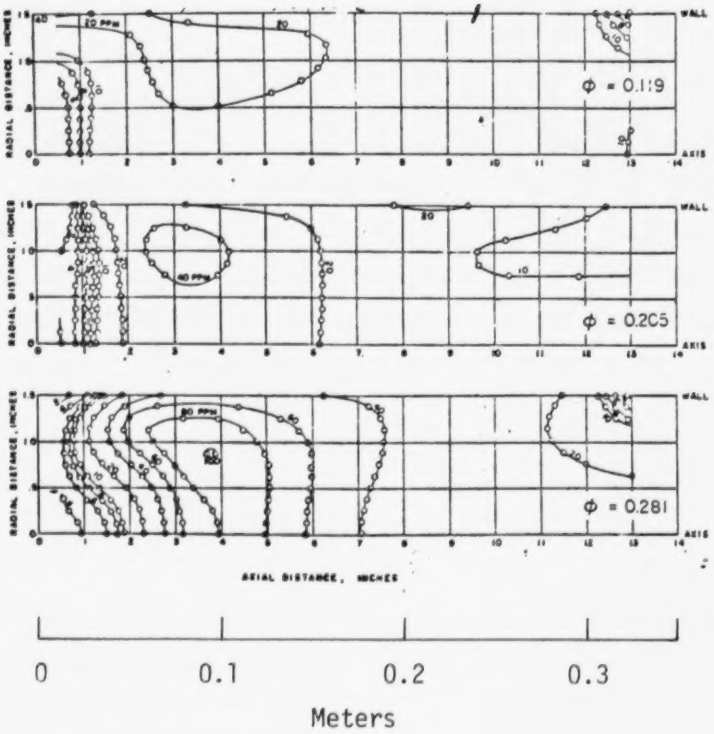

Figure 4-6. Nitric oxide concentration maps of a laboratory scale gas combustor (Reference 4-15). (Reproduced by permission of the ASME.)

A second phenomenon which promotes NO_x production is dwell time, or residence time, of the combustion components in the hot regions of the combustion chamber. Figure 4-7 illustrates this concept for combustion of premixed, prevaporized propane fuel in a lean primary zone combustor typical of today's engines. NO_x is plotted as a function of residence time with equivalence ratio as a parameter (Reference 4-5). The intersection of the combustion efficiency curves with the NO_x curves gives the residence time required to achieve a given efficiency at a given equivalence ratio. Note that residence time is a strong factor in NO_x formation only at high equivalence ratio. It follows therefore, that NO_x emissions increase with increasing equivalence ratio. The figure further suggests that the way to achieve the lowest possible NO_x emissions while maintaining high combustion efficiency is to burn as lean as possible but to allow long residence times (Reference 4-5). Figure 4-4 also shows how less NO_x is produced in the primary reaction zone of a flame as the mixture becomes more lean. Recent data from Pratt & Whitney has shown that in a newly developed, full-scale combustor with rich burning in the primary zone and firing fuels containing bound nitrogen, NO_x emissions decrease with increasing residence time.

Other mechanisms related to time, temperature, and mixing, impact the NO_x emission levels. Turbulence (or the degree of mixing) can affect NO_x emissions and is dependent on the type of fuel. As seen in Figure 4-8, liquid fuels generally result in higher NO_x emissions than gaseous fuels (Reference 4-17). However, this is partly due to the fact that liquid fuels tend to have fuel bound nitrogen (which can contribute to the total NO_x emissions) as well as to such factors as degree of mixing. Therefore the comparison between liquid and gaseous fuels should only be made in cases of relatively nitrogen free fuels such as distillate oil and natural gas (methane). Gas fuels can be effectively mixed with combustion air with high turbulence to produce a uniform fuel/air mixture throughout the combustion zone and hence, uniform temperatures. By reducing localized combustion temperature, NO_x emission levels can also be reduced (Reference 4-5). Tests have also shown that better mixing can reduce NO_x formation when firing liquid fuels (Reference 4-5).

Combustion of liquid fuels which are not prevaporized can be thought of as droplet burning. The fuel is atomized and mixed with air in

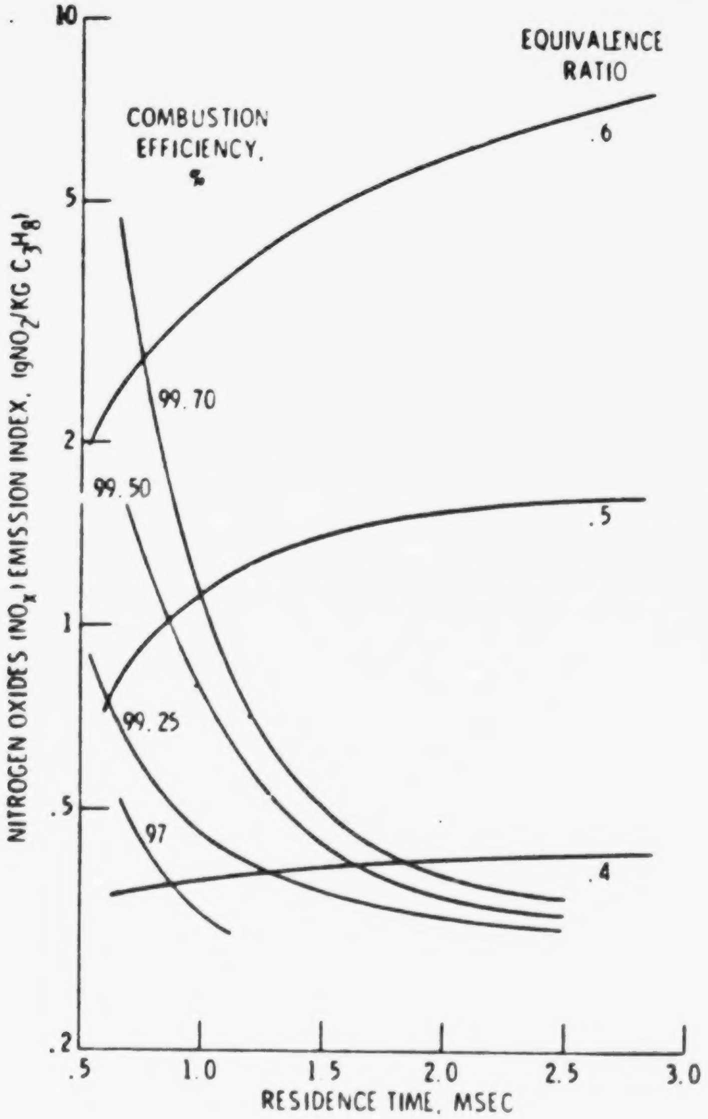

Figure 4-7. Effect of residence time on nitrogen oxides emissions for a lean primary combustor. Propane fuel inlet mixture temperature, 800K; inlet pressure, 5.5 atm; reference velocity 25 and 30 m/s (Reference 4-5).

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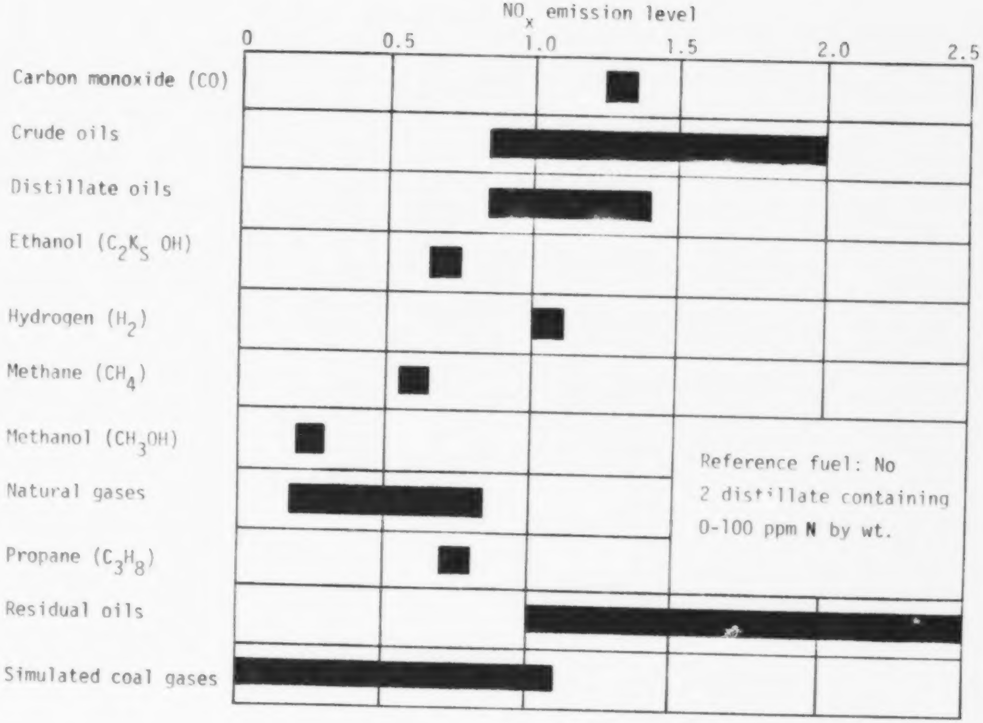

Figure 4-8. Predicted NO_x emission levels of various fuels burning in gas turbine combustors (NO_x levels are normalized to emissions from burning #2 fuel oil) (Reference 4-17).

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the combustion chamber. Droplet burning is one mechanism by which burning can result in local flame temperatures in excess of the mean combustion zone temperature due to non-uniformities in the fuel/air ratio (Reference 4-5). The more energy used for atomization and fuel/air mixing, the more uniform is the combustion and resulting temperature, thus producing less thermal NO_x, at least in a fuel lean primary zone. Note that the proper fuel/air mixing for lowering NO_x emissions with more uniform combustion temperatures should be balanced against the opposing effect of greater NO_x formation due to better oxygen availability, as discussed earlier. Thus proper NO_x control requires controlled fuel/air mixing.

The above effects have led to several control mechanisms which promote good mixing of fuel and air. One such mechanism is to promote turbulent mixing within the combustion chamber. Another mechanism has to do with increasing the atomization of liquid fuel. This can be accomplished through preheating or prevaporization of the fuel. The efficiency of fuel atomization is a function of the fuel viscosity (Reference 4-18).

Still another concept is that of premixed fuel/air charges. This is also known as hybrid combustion (Reference 4-19). The fuel and primary combustion air are allowed to mix thoroughly prior to ignition in the primary combustion zone (Reference 4-20). Figure 4-9 schematically shows the postulated effect of premixed combustion mixture as opposed to standard combustion techniques. Emissions at various equivalence ratios using premixed systems are also shown.

It should be stressed, however, that these techniques to enhance fuel/air mixing generally work only with lean primary burning of fuels low in bound nitrogen. These principles may not be true with rich primary burning of high bound nitrogen fuels.

Nitric Oxide/Nitrogen Dioxide

The relationship between nitric oxide emissions and total NO_x for propane combustion is shown in Figure 4-10. Nitric oxide accounts for about 90 percent of the total NO_x for most conditions (Reference 4-5). This is typical of stationary source combustion of conventional fuels (Reference 4-16). The remaining NO_x is emitted as NO_2.

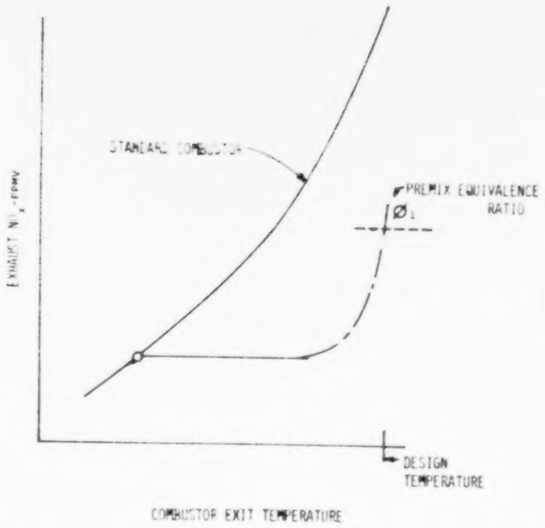

Figure 4-9. NO$_x$ emission trends of a hybrid combustor versus a conventional combustor (Reference 4-19).

(Reproduced by permission of the ASME.)

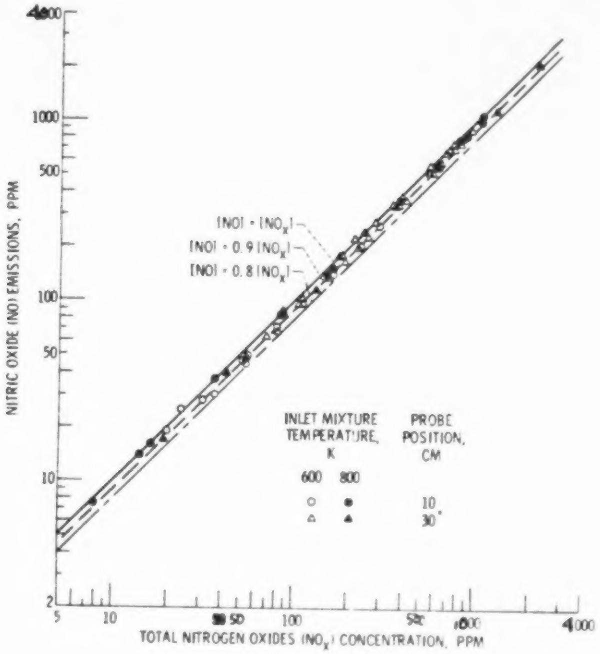

Figure 4-10. Relationship between nitric oxide emissions and total NO$_x$ for propane combustion. Inlet pressure, 5.5 atm; reference velocity, 25 m/s; equivalence ratio, 0.40 to 1.0 (Reference 4-5).
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Other criteria pollutants include carbon monoxide (CO) and unburned hydrocarbons (UHC). The quantity of each depends on the completeness of combustion. The concentration of each is expected to be affected by changes in operations for the reduction of NO_x. For example, reductions in combustion temperatures may reduce NO_x emissions but increase the CO and UHC concentrations. A balance between NO_x and the other criteria pollutants must be maintained. The effect of NO_x controls on other pollutants is discussed in greater detail in Section 6.

4.2.4 Products Characterization

The principle product of a gas turbine is rotary shaft power. The exhaust gas from a gas turbine combustor can also be considered a "product." The hot exhaust gas can be used to supply waste heat via a heat recovery device or, by virtue of its high excess oxygen content and waste heat content, be used in a supplementary fuel fired waste heat boiler. The product exhaust gas from a gas turbine is discussed in further detail in the next Section, Emissions Characterization.

4.3 EMISSIONS CHARACTERIZATION

The emissions from a gas turbine without NO_x controls will primarily be a function of the fuel composition, combustor geometry and operating conditions of the system. Emissions of concern include NO_x, SO_2, CO, particulates, and unburned hydrocarbons.

Emission factors for uncontrolled emissions for the criteria pollutants from gas turbines are presented in Table 4-5. The emission factors come from field studies (References 4-10, 4-21, and 4-22) and an EPA Document, AP-42 with supplements (Reference 4-23). Emission factors for organic matter and sulfates from gas turbines cannot be determined at present since extensive field test results have not yet been reported. There are no liquid or solid effluents resulting from combustion related gas turbine operation (with no NO_x controls).

4.3.1 NO_x Emissions

The amount of fuel bound nitrogen converted to NO_x is a function of the supply of oxygen available for reaction. The degree of conversion from Figure 4-2, also depends on the degree of fuel/air mixing. Thermal NO_x is a function of many variables, as described in the previous section. Again, efforts to control NO_x must be carefully applied to assure acceptable emission rates of the other criteria pollutants.

TABLE 4-5. GAS TURBINE CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Equipment Types	NO_x	SO_x	Part.	CO	HC
Gas Turbines >15 MW (output)					
Natural Gas	194	2.2	6.0	49.0	8.6
Diesel oil	365	10.7	16.0	47.0	8.6
Gas Turbines 4 MW to 15 MW (output)					
Natural Gas	194	2.2	6.0	49.4	8.2
Diesel oil	365	10.7	15.5	47.3	9.9
Gas Turbines <4 MW (output)					
Natural Gas	194	2.2	6.0	49.4	8.2
Diesel oil	365	10.7	15.5	47.3	9.9

4.3.2 SO_2 Emissions

Sulfur oxide emissions are almost exclusively a function of the sulfur content of the fuel (Reference 4-10). SO_2 emissions are controlled by burning low sulfur fuels. Some sulfur removal from fuels is practiced, but only to a limited degree.

4.3.3 Particulate and Visible Emissions

Particulate emissions from gas turbines are a function of the ash content of the fuel and combustion efficiency. Emissions from natural gas firing are typically low, approximately 0.005 g/scm (0.002 gr/scf) of gas, with residual oil emissions approximately 0.24 g/scm (0.10 gr/scf). Magnesium and other inhibitors added to liquid fuels to reduce vanadium corrosion can also contribute to particulate emissions (Reference 4-10). Reductions in visible and particulate emissions can be obtained by burning clean fuels such as gas, and through combustor modifications for improvement of the combustion efficiency.

4.3.4 Hydrocarbons and Carbon Monoxide Emissions

Hydrocarbon and CO emissions are functions of the combustion efficiency of the unit. Since most units are designed for high efficiency at maximum load, reduced load tends to cause the occurrence of increases in CO and HC concentrations. Carbon monoxide reacts slowest of all components formed during combustion, therefore it is emitted in the largest concentrations. Figures 4-11 and 4-12 show the wide variations that can occur as a function of unit size, operating conditions, fuel type, and probably most significantly, design changes as sizes get larger. Note that the values reported in the figures have been diluted to 15 percent oxygen.

The complete combustion of HC and CO emissions is a function of the method of fuel injection, including atomization method and pressure, degree of fuel/air mixing, and the residence time at combustion temperature. It should be noted that improved atomization and fuel/air mixing can reduce thermal NO_x as CO and HC are reduced. However, increased residence time and combustion temperature for more complete combustion may increase NO_x, at least for fuel-lean primary zone combustors. This is not the case with fuel-rich primary zone combustors.

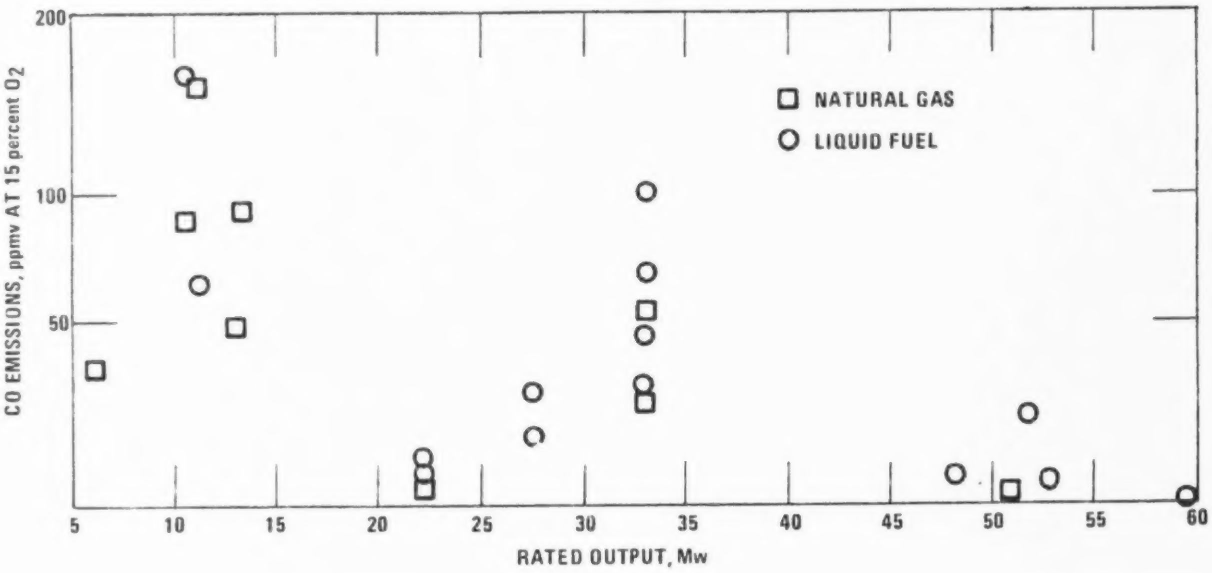

Figure 4-11. CO emissions vs. turbine size for large gas turbines without NO_x controls when operated at or near full load (Reference 4-10).

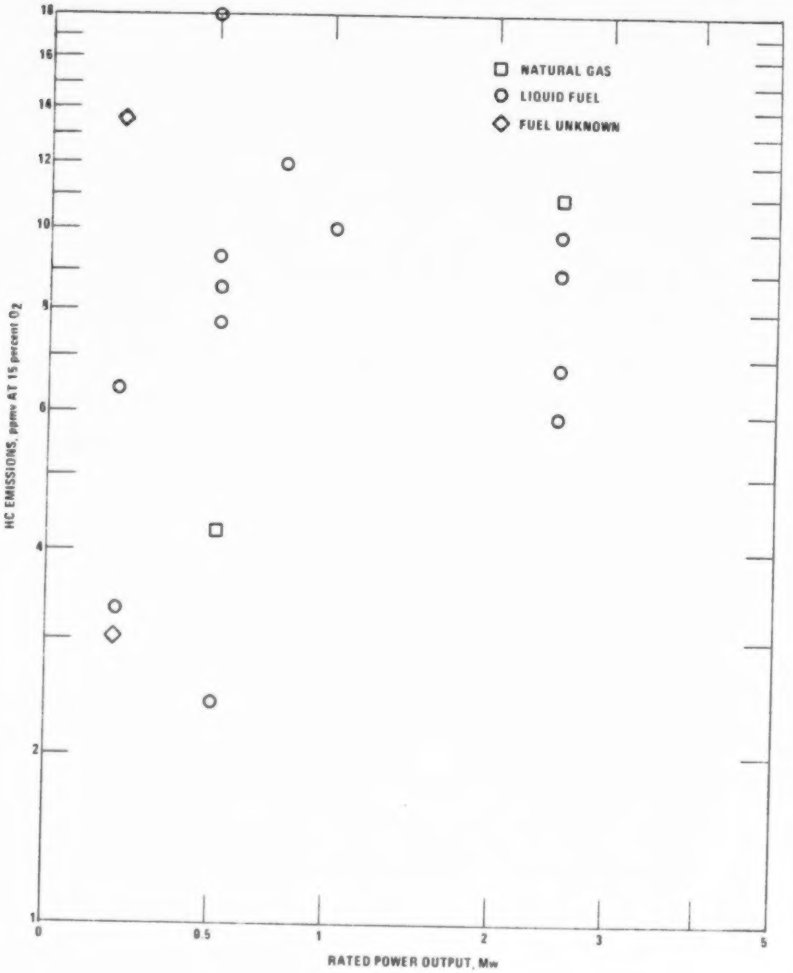

Figure 4-12. HC emissions vs. turbine size for small gas turbines without NO_x controls when operated at or near full load (Reference 4-10).

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SECTION 5

PERFORMANCE AND COST OF CONTROL ALTERNATIVES

Stationary gas turbines are characterized by a wide variety of equipment types, cycle types, fuel requirements, and applications. All of these factors contribute to a high degree of variability on the pollution control potential from a specific turbine. Indeed, even gas turbines of the same model and production run can have significantly different NO_x emissions (Reference 5-1). For example, small machining differences in fuel nozzles and air dilution holes can significantly affect localized fuel/air ratios and residence times and ultimately NO_x generation.

This section evaluates the performance of existing and planned pollution controls for stationary gas turbines. Since NO_x is the principle and major pollutant of concern from gas turbines, the great emphasis here is on NO_x controls (Reference 5-2). Control options for other pollutants are reviewed briefly in subsection 5.5. To make the control evaluation meaningful and useful to researchers, regulatory agencies and potential control users, pollutant reduction and/or prevention must be considered, and the associated costs and impacts on operations and maintenance must be analyzed.

5.1 PROCEDURES FOR EVALUATING CONTROL ALTERNATIVES

Ideally, consistent analysis and comparison procedures would be used to judge fairly the effectiveness of various control alternatives. These procedures would be applied to data obtained from tests and analyses of actual full scale stationary gas turbines. However, there is a paucity of data from long term control experience which can be applied to such analysis procedures. The reason for this lack of data is that only a few regions in this country have promulgated emissions standards for stationary gas turbines (see subsection 6.3.1). And those that have, for the most part, have been promulgated for only 1 to 3 years. Only certain counties in the South Coast California Air Quality Management District in Southern California have had standards regulating NO_x emissions from stationary gas turbines for more than 3 years (almost 7 years for Los Angeles County). Of course, many stationary gas turbines that are not in regulated regions have NO_x controls (i.e., water injection). However, they are seldom used unless required by local NO_x regulations.

Consequently this assessment relied on three primary sources of data: users, manufacturers, and EPA, notably through the "Standards Support and Environmental Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines" (Reference 5-3).

The approach taken here is to compare baseline gas turbine operation with that under controlled and low NO_x conditions. In addition to pollutant reduction, other factors considered in comparing the effectiveness of NO_x controls are fuels, incremental emissions of pollutants other than NO_x, control economics, operating reliability, additional maintenance requirements, current stage of control development, and expected timescale of commercialization for new control technologies. As mentioned earlier, data based on long term user experience with NO_x controls are limited. Consequently, to compare baseline and controlled firing, this investigation had to rely to a great extent on informed conjecture and qualitative engineering judgement, particularly in assessing operations and maintenance impacts. Furthermore, the available user experience is extremely variable, if not contradictory. In general, some problem areas have been identified; their frequency and degree depend on equipment types, operating parameters and quality of maintenance.

The assessment of the economic impact due to NO_x control techniques has had to rely to a great extent on real-time data supplied by a few users and to a lesser extent, on costs quoted by manufacturers. The manufacturer's figures are primarily for capital equipment costs and do not include incremental operating costs. Much of the cost data was used to update and confirm costs cited in the SSEIS. In performing a comprehensive cost analysis, a significant hinderance was that many users had never attempted to separate and specifically account for costs of wet NO_x controls. Rather they simply looked at operating and maintenance costs on a total turbine basis, not on a component by component basis.

An additional concern when evaluating NO_x control alternatives was the current state of development and the expected timescale of commercialization of developing control concepts. For example, while catalytic combustion appears to perform quite well in reducing all pollutants from clean fuels in particular (98 percent reduction -- Reference 5-4), it is far from developed for use in full scale combustors and consequently many years from fruition. Indeed, some manufacturers have expressed skepticism whether it will ever become a reality for use with stationary gas turbines (Reference 5-5).

There are a number of other factors that may cause delays in the development of control techniques and that make evaluation difficult. First, is the depressed domestic market for gas turbines. Although a slow reversal of the trend is expected, the current sales picture is very weak (Reference 5-6). Also there is a major hesitancy to invest in control technique development because NSPS has only recently been promulgated. Furthermore, development of new combustors is very expensive, approaching $20 million to get a new combustor into a full-scale engine. Also the fuels situation is unclear. Will clean fuels (low in fuel-bound nitrogen) continue to be available, or will developers and users be forced to design for dirty fuels? And finally, most development work is aimed at improving thermal efficiency through higher turbine inlet temperatures, higher pressure ratios, and combined cycles. This situation is forced by gas turbines' competitive position with IC engines which generally have higher cycle efficiencies.

Ultimately, after review of current and future control technologies, assessment of process and cost impacts, and emissions reviews, this study will arrive at conclusions regarding the cost effectiveness of particular NO_x control alternatives. Those controls that show the best balance between emissions reduction performance and capital and operating costs will be identified.

For all the control options studied, the analyses have been conducted based on the currently available data. It must be remembered that the figures are general and can vary widely for different installations. In addition, there are still many unanswered questions regarding long term cost, operations and maintenance data. Due to the changeable nature of the gas turbine market and the current state of flux in control developments, these questions may become moot by the time they can be reliably answered.

5.2 PERFORMANCE AND COST OF NO_x CONTROL ALTERNATIVES

For all intents and purposes, the only gas turbine waste streams resulting from combustion are exhaust emissions. The most effective and economical way of reducing these emissions is by modifying combustion process conditions. This subsection reviews the currently used and developmental combustion modification techniques for control of exhaust emissions. Also, because NO_x emissions, the primary gas turbine effluent, are highly dependent on fuels as well as combustor design and control technique, special emphasis is put on controls and the fuels designed for.

Since stationary gas turbines typically operate at rated capacity, combustion efficiencies are high. Complete combustion, while minimizing production of CO and UHC, tends to maximize production of nitrogen oxides. Sulfur dioxide emissions are solely a function of the fuel sulfur content and are controlled by burning fuels with low sulfur content. Particulate emissions are low because clean fuels (natural gas and distillate oil with little or no ash) are generally used by gas turbines.

5.2.1 Control Techniques and Fuels

NO_x controls for gas turbines are usually classified into two categories: wet techniques which inject water or steam into the combustion zone, and dry techniques which involve some process modification other than the addition of water. This typically takes the form of combustor redesign. The following discussion reviews the performance of wet and dry techniques while they are burning clean and dirty fuels. Dirty fuels are those which are high in fuel-bound nitrogen. Each will be treated separately in the following discussion. The distinction is made due to the performance of certain control concepts with certain fuel types. Subsequent discussions then focus on the impact of these NO_x controls on other pollutants (Subsection 5.2.2). Finally, the cost impact of these controls will be analyzed (Subsection 5.2.3).

5.2.1.1 Wet Control Techniques and Clean Fuels

The formation of thermal NO_x is highly dependent on flame temperature. In fact, virtually all thermal NO_x is formed in the region of highest flame temperature and amounts formed increase exponentially with increasing temperature as shown in Figure 5-1. With the injection of atomized water or steam directly into the primary combustion zone, peak flame temperatures are lowered which effectively lower NO_x. The heat of vaporization of the injected water effectively removes some of the heat from the primary combustion zone. NO_x emission reductions as great as 80 percent have been achieved with water injection on gas turbines. Figure 5-2, updated from Reference 5-3, summarizes NO_x emissions data from a variety of gas turbines using wet controls and firing clean fuels. Figure 5-3, also updated from Reference 5-3, indicates the effectiveness of water or steam injection in reducing NO_x emissions.

Typically, water injection equipment is skid-mounted while the operating controls are mounted in the turbine control compartment. Typical components of the water injection system include the water injection pump, pump inlet strainers, a filter for outlet water, flow meter, valves, motor starters, heaters, piping and instrumentation. A mechanical components schematic from one gas turbine manufacturer is shown in Figure 5-4. The electrical control schematic from the same manufacturer is shown in Figure 5-5. This particular system is designed to inject water over the complete load range to maintain the proper water-to-fuel ratio predetermined to limit NO_x emissions to the federal standard (Reference 5-7). Upon promulgation of the Standards of Performance for New Stationary Gas Turbines, this capability is be required for all gas turbines subject to the regulations. It is important to note, however, that these engine controls are limited to existing engines and current combustors. These controls and water injection would not be suitable for new concepts such as premixing/prevaporization and superclean combustors.

Water injection is commonly accepted as a valid technology to control nitrogen oxides emissions from current combustor design. In fact, General Electric currently has 16 Model MS 5001 and 43 Model MS 7001 gas turbines equipped with water injection equipment (Reference 5-7). Some of these are used to meet local air pollution regulations while others are used to increase power output by increasing mass flow rates through the turbine. One manufacturer guarantees their gas turbine NO_x emissions to

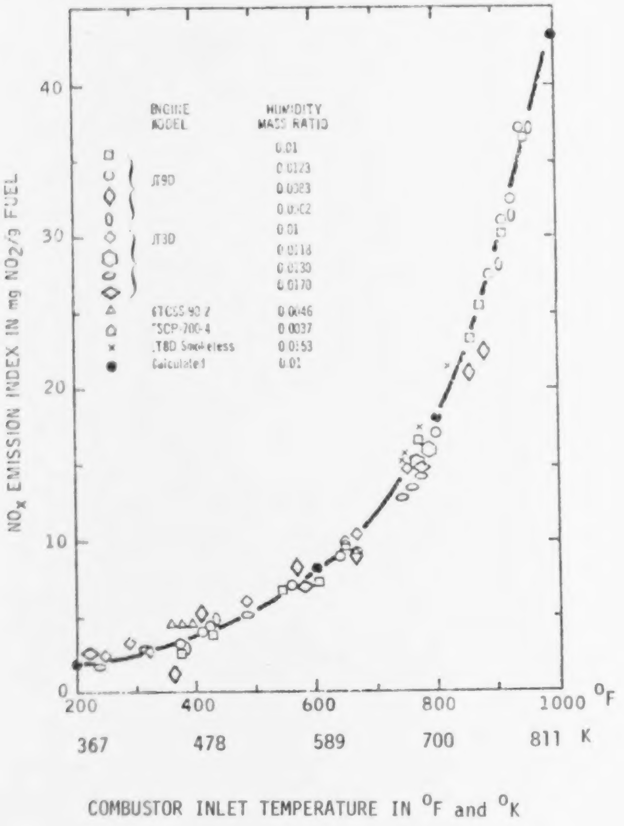

Figure 5-1. NO_x emission index versus gas turbine combustor inlet temperature (Reference 5-3).

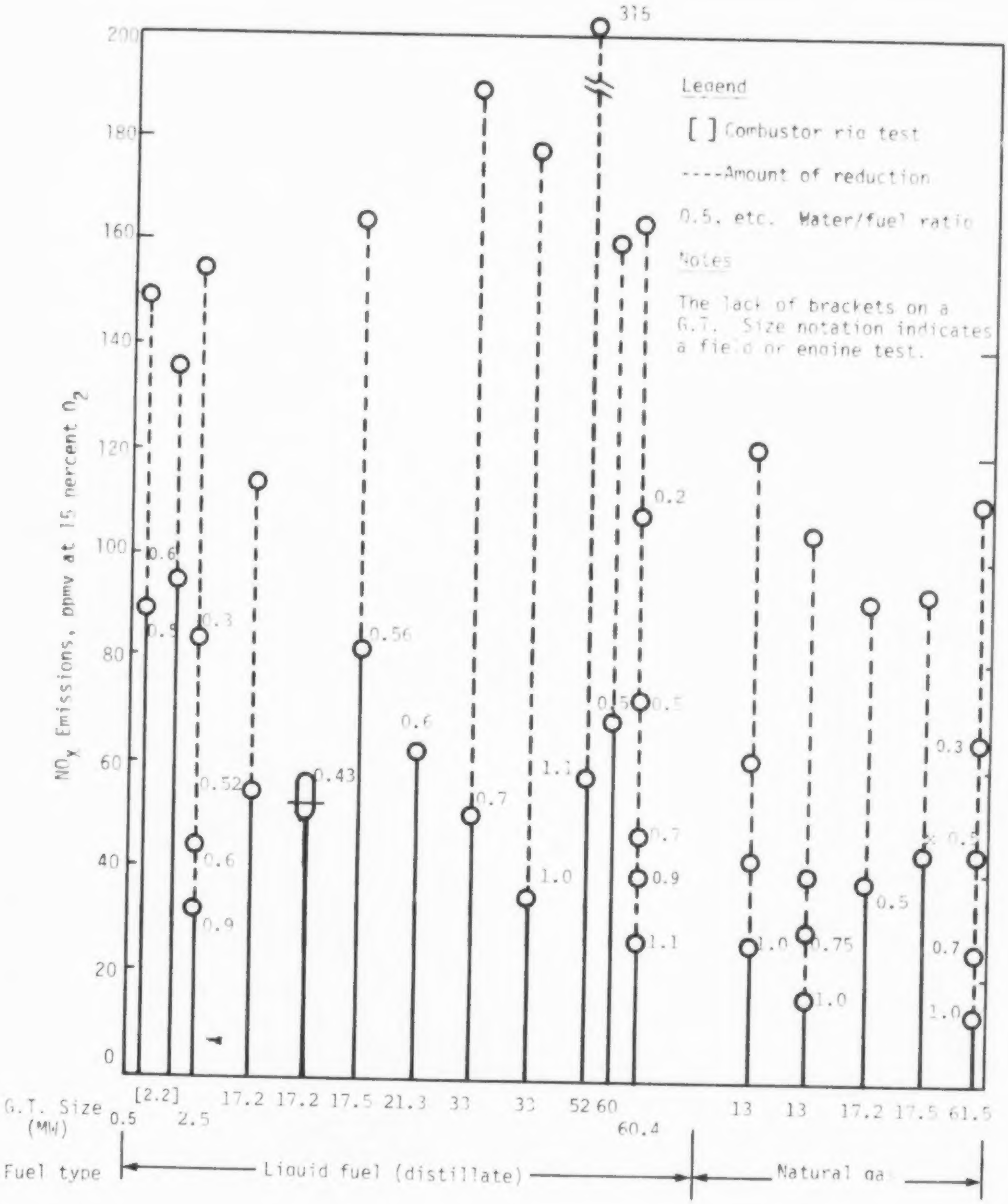

Figure 5-2. Summary of NO$_X$ emission data from gas turbines using wet control techniques (Reference 5-3).

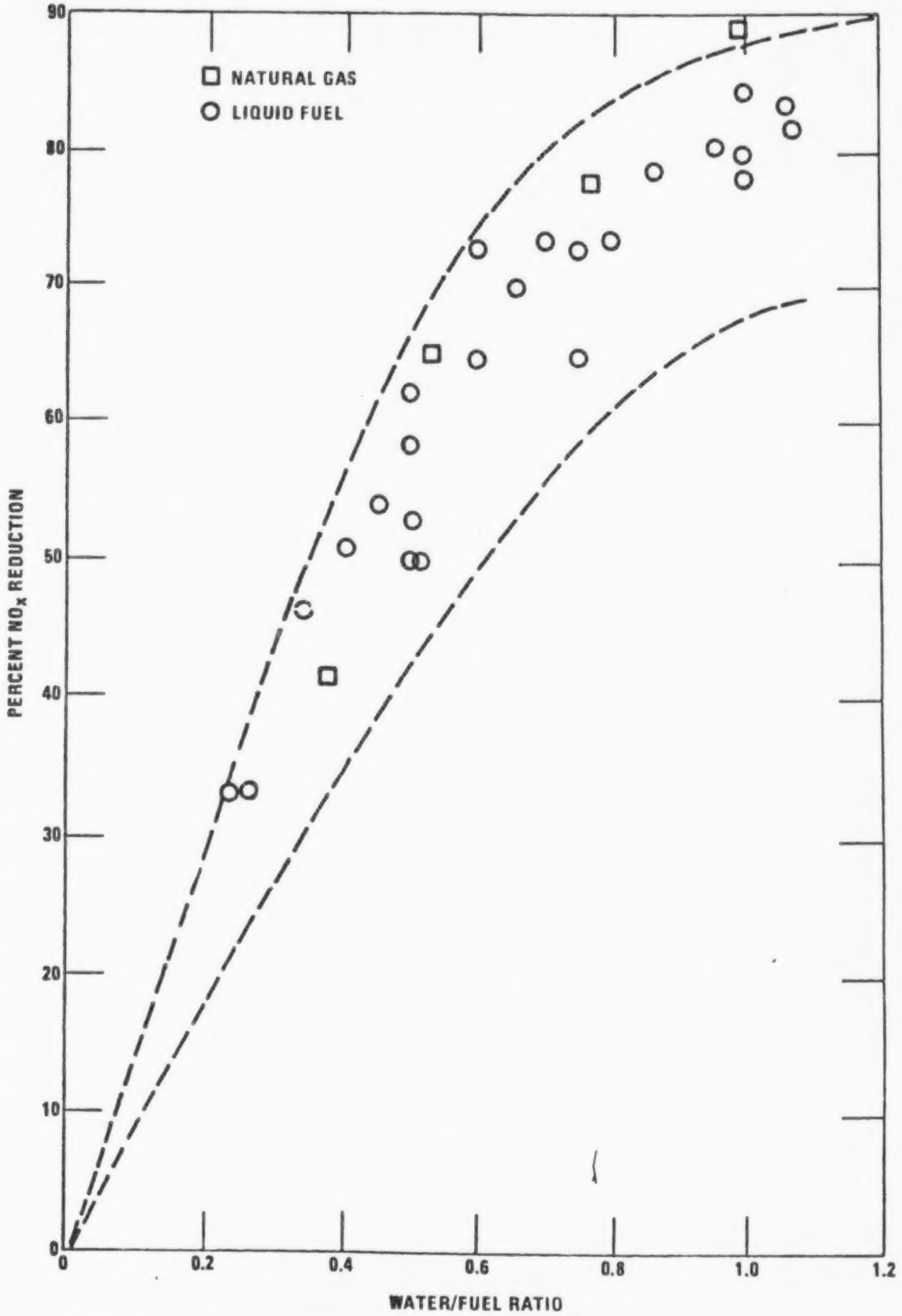

Figure 5-3. Effectiveness of water/steam injection in reducing NO_x emissions (updated from Reference 5-3).

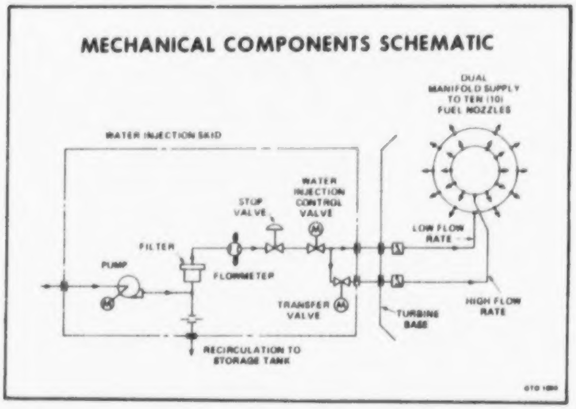
MECHANICAL COMPONENTS SCHEMATIC
DUAL MANIFOLD SUPPLY TO TEN (10) FUEL NOZZLES
WATER INJECTION SKID
WATER INJECTION CONTROL VALVE
STOP VALVE
LOW FLOW RATE
FILTER
PUMP
FLOWMETER
TRANSFER VALVE
TURBINE BASE
HIGH FLOW RATE
RECIRCULATION TO STORAGE TANK
M
M
M

Figure 5-4. Mechanical components schematic (Reference 5-6). (Reproduced by permission of the Gas Turbine World.)

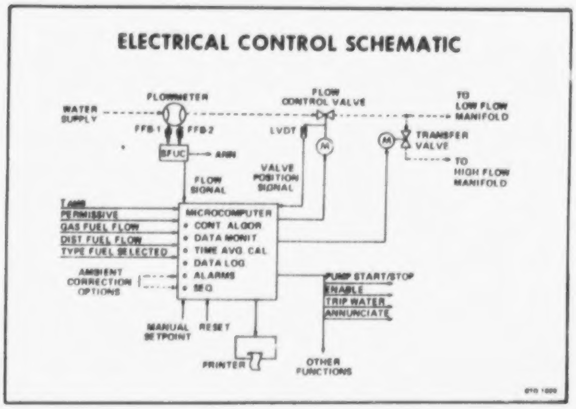
ELECTRICAL CONTROL SCHEMATIC
FLOWMETER
FLOW CONTROL VALVE
TO LOW FLOW MANIFOLD
WATER SUPPLY
FFB-1
FFB-2
LVDT
TRANSFER VALVE
BFUC
ARM
TO HIGH FLOW MANIFOLD
VALVE POSITION SIGNAL
FLOW SIGNAL
PERMISSIVE
GAS FUEL FLOW
DIST FUEL FLOW
TYPE FUEL SELECTED
MICROCOMPUTER
• CONT ALGOR
• DATA MONIT
• TIME AVG CAL
• DATA LOG
• ALARMS
• SEQ
AMBIENT CORRECTION OPTIONS
PUMP START/STOP
ENABLE
TRIP WATER
ANNUNCIATE
MANUAL SETPOINT
RESET
PRINTER
OTHER FUNCTIONS

Figure 5-5. Electrical control schematic (Reference 5-6). (Reproduced by permission of the Gas Turbine World.)

75 ppm at 15 percent oxygen in the flue gas, while another will supply wet controls on an "as needed" basis.

Strict specifications for water quality are required to prevent excessive corrosion in hot gas turbine parts. Control of impurities is essential to maximize turbine life and keep the system economically viable. Gas turbine water injection equipment does not require as stringent water quality standards as does a steam boiler. General specifications for turbines and boiler feedwater are shown in Table 5-1 (Reference 5-3). Water treatment requirements do vary somewhat between turbines, depending mostly on the type of fuel burned. Turbine manufacturers often specify total contaminants allowed in the turbine, including those contributed by the fuel, water and combustion air. Although water quality requirements vary to a small degree, water use requirements can vary greatly among turbines. The water-to-fuel ratio for optimum NO_x reduction can vary from 0.5 to 1.0 (Reference 5-8). It depends on such factors as combustor design, plant location, heat rate, turbine inlet temperature, fuel characteristics (primarily fuel nitrogen content), and operating mode. On a total volume basis, the water requirements for NO_x control are small. Consequently, siting of a gas turbine generating station should not become a difficult problem due to water availability, except possibly in arid or arctic regions. However, there is a cost impact, which is discussed in subsection 5.2.3.

Water purification systems typically employ a series of filters followed by a reverse osmosis unit and a demineralizer or deionization unit. Figure 5-6 shows a water treatment system sized to provide water injection for operating five 28 MW gas turbines 10 hours per day. The high degree of cleanup that the reverse osmosis unit attains minimizes the size requirements for the demineralizer and deionization unit with an attendant cost savings.

Wet controls for thermal NO_x reduction have thus proven to be very effective in stationary gas turbines of current design and with relatively clean fuels. The effect that water or steam injection has on incremental emissions (i.e., changes in emissions of pollutants other than NO_x) and on the gas turbine operations and maintenance requirements is discussed in subsections 5.2.2 and 6.5, respectively.

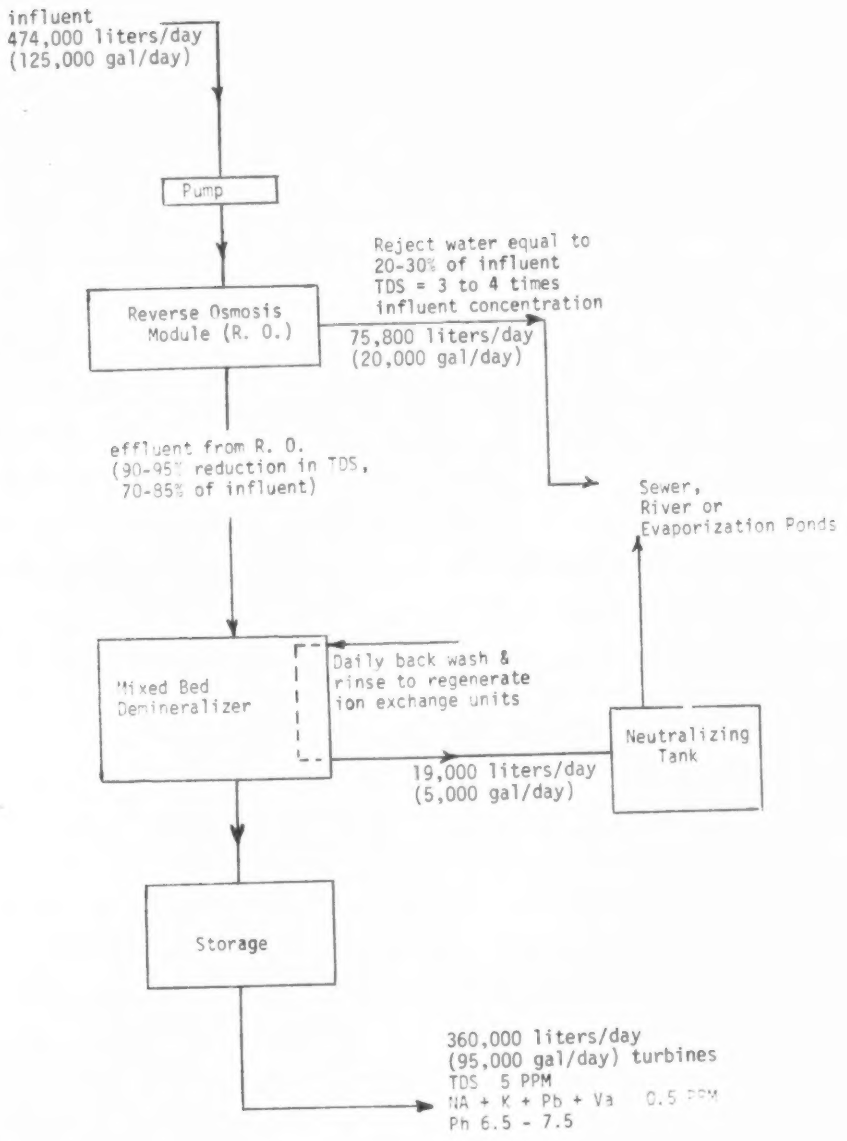
influent
474,000 liters/day
(125,000 gal/day)
Pump
Reverse Osmosis Module (R. O.)
Reject water equal to
20-30% of influent
TDS = 3 to 4 times
influent concentration
75,800 liters/day
(20,000 gal/day)
effluent from R. O.
(90-95% reduction in TDS,
70-85% of influent)
Sewer,
River or
Evaporization Ponds
Mixed Bed Demineralizer
Daily back wash &
rinse to regenerate
ion exchange units
Neutralizing Tank
19,000 liters/day
(5,000 gal/day)
Storage
360,000 liters/day
(95,000 gal/day) turbines
TDS 5 PPM
NA + K + Pb + Va 0.5 PPM
Ph 6.5 - 7.5

Figure 5-6. Water treatment system (Reference 5-3).

TABLE 5-1. TYPICAL WATER QUALITY SPECIFICATIONS
(Reference 5-3)

	Turbine	Boiler Feedwater
Total dissolved solids + Non dissolved solids (ppm)	1.0 - 5.0	0.25
Sodium + potassium (ppm)	0.5	0.25
Silica (ppm)	0.02	0.0
Particle size (μm)	10.0	--
pH	7.0 - 8.5	6.5 - 7.0

5.2.1.2 Wet Control Techniques and Dirty Fuels

Water and steam injection have been demonstrated in a number of full-scale installations to be effective in controlling NO_x emissions. However, recent studies have shown that the effectiveness of wet controls decreases significantly as the percentage of fuel-bound nitrogen (FBN) in a fuel increases. Wet controls control primarily thermal NO_x production, but as fuel nitrogen increases, fuel NO_x can predominate. Wet controls can actually be counter-productive. Cohn, et al. (Reference 5-9) have shown in tests in a subscale combustor version of a commercial Westinghouse unit, that the performance of water injection decreases significantly with high nitrogen fuels such as solvent refined coal (SRC) fuels. Indeed, Figure 5-7 shows that with a high water-to-fuel mass ratio and a high-nitrogen fuel, water injection is actually detrimental to NO_x reduction.

5.2.1.3 Dry Control Techniques and Clean Fuels

Controlling emissions from gas turbines can be a very difficult task, primarily because of the nature of their operating cycles. As engines attain maximum load, emissions of NO_x are maximized. From the operator standpoint, this is a preferred condition since overall thermal efficiencies are also maximized. Under partial load conditions or in a

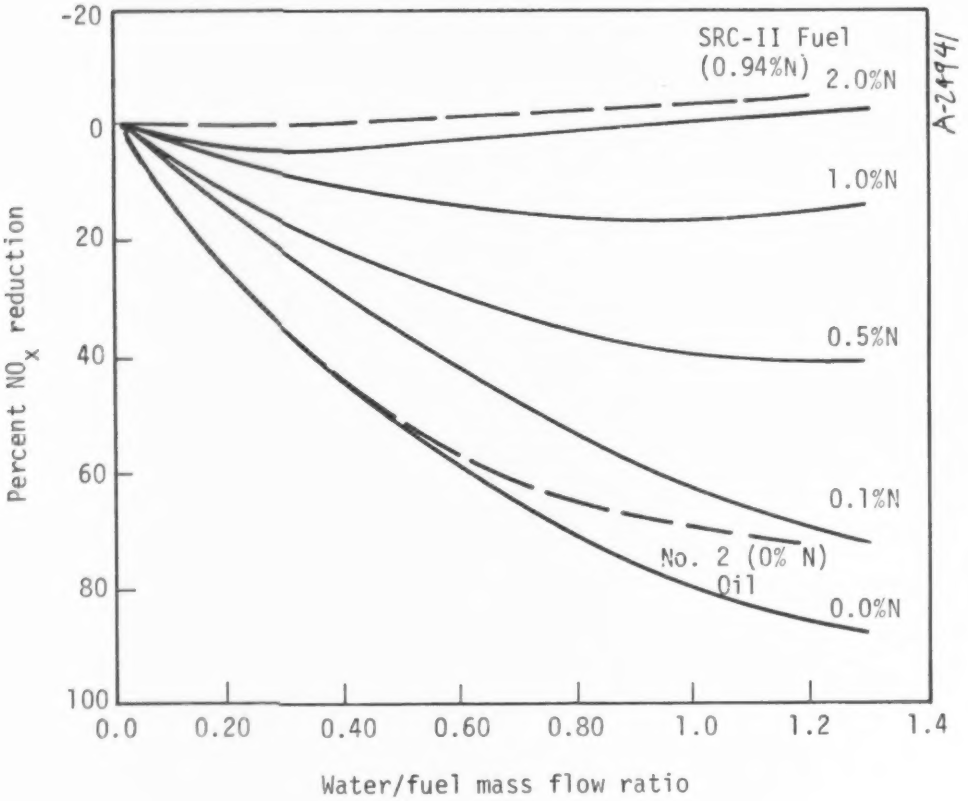

Figure 5-7. Predicted decrease in NO_x emissions through water injection with increasing amounts of bound nitrogen in fuel oil (Reference 5-9).

start-up/shut-down mode, NO_x emissions decrease, but due to poorer combustion efficiency, emissions of CO and unburned hydrocarbons increase. Consequently an emissions tradeoff situation exists in existing combustor designs. While it is desirable to decrease NO_x emissions, it is also undesirable to increase CO emissions. This can become a particularly important consideration in local nonattainment areas with a cluster of gas turbines operating in the spinning reverse mode (i.e., low load in an electric utility system). Modeling studies performed by EPA have shown this particular arrangement to cause sufficient CO emissions to cause local violations of the National Ambient Air Quality Standards (NAAQS) (Reference 5-3). It must be kept in mind that this is but one example. The factors affecting gas turbine emissions and their effect on ambient air quality are numerous and certainly not limited to the combustor zone reactions.

However, the combustor itself is where emissions are most effectively reduced. The amount of NO_x formed in any combustion process is a function of:

- Flame temperature
- Dwell time of the combustion gases at peak flame temperatures
- Fuel/air mixing
- Quantity of oxygen and nitrogen present
- Fuel atomization and vaporization
- Combustor pressure

Flame temperature increases when combustion air temperature is raised and as the fuel-to-air ratio in the primary combustion zone approaches stoichiometric values. Gas velocity and combustor zone dimensions generally define the dwell times. Thus, as compression ratios and turbine inlet temperatures increase to improve thermal efficiency and net plant heat rate, NO_x generation in the combustors of stationary gas turbines will increase significantly. By 1986, uncontrolled thermal NO_x generation is expected to double over today's values while by 1996, they are expected to triple (Reference 5-10). This estimate does not take into account NO_x generated from fuel bound nitrogen. In the future, as economics and availability reverse the present trend and make the dirtier fuels with higher fuel bound nitrogen more attractive, then these NO_x emissions estimates will increase even more (without NO_x controls).

In chronological order, the technological advances that are expected to increase compression ratios and turbine inlet temperatures are: 1) convectively cooled turbine airfoils, 2) precooled turbine cooling air, 3) water cooled vanes and 4) water cooled airfoils.

All of this points to the fact that a combustion modification NO_x control technique is required that is more acceptable to stationary gas turbine users and manufacturers while, at the same time, meets NO_x emissions regulations. Dry controls (any control technique that does not involve water injection and requires design or operational modifications) are expected to provide this capability, by some estimates in 1982 (Reference 5-11).

Among the most promising dry NO_x control strategies are:

- Improved fuel premixing and prevaporization
- Fuel rich combustion in the primary zone
- Primary zone heat removal
- Controlled fuel/air ratio distribution
- Extended flammability limits for ultralean combustion
- Catalytic combustion

These are general strategies and many methods exist to attain one of these general results. For example, the general strategy of controlled fuel/air ratio distribution can include the specific techniques of fuel staging, air staging, fuel/air premixing and virtual staging. Furthermore, each of these techniques responds differently to different fuels. The discussion in this section concerns those programs which have developed dry NO_x control techniques for clean fuels (i.e. those fuels low in bound nitrogen).

Much of the past and current developmental work with clean fuels is directed towards superlean primary zone combustors. One study by the Pratt and Whitney Aircraft Group looked at 26 potential dry NO_x control concepts, analytically screened them, and selected the most promising for extended experimental evaluation on bench scale hardware (Reference 5-10). The first concept tested in bench-scale equipment was the staged centertube -- a super-lean configuration which proved effective only on clean fuels. CO and NO_x were found to be controllable in the range of 25 to 50 ppmv over a range of operating conditions. A major limiting factor to further development was a need for variable geometry in the combustor. Additional results from this program with a rich primary zone, lean secondary zone and clean fuels are discussed later in this section. The results of additional work while burning dirty fuels is discussed in Section 5.2.1.4.

As part of NASA's experimental clean combustor program, General Electric Company and Pratt and Whitney Aircraft (References 5-12 and 5-13) have each performed tests using advanced combustor designs to minimize emissions of NO_x, CO, HC and smoke under all operating conditions, idle to full power. The important results of those programs are briefly discussed here. A more extensive summary of each program can be found in Reference 5-3. General Electric's program involved four different combustor designs and included such emission control concepts as lean burning, fuel/air premixing and fuel and air staging. Pratt and Whitney tested three different combustor designs. The emission control concepts investigated were fundamentally similar to General Electric's, although specific approaches varied. Both programs resulted in a maximum of approximately 60 percent NO_x reduction; General Electric with a radial/axial staged combustor with premix and lean primary combustion and Pratt and Whitney with their Swirl Vorbix configuration. This particular combustor provided for long residence time at idle to maximize CO and HC oxidation and rapid burning and quenching at full power to minimize NO_x.

The concept of lean burning and prevaporization and premixing fuel has been found to be very effective in reducing NO_x emissions when burning fuels containing negligible amounts of fuel bound nitrogen. Two aircraft combustor concepts developed by Solar proved very successful in substantially reducing NO_x emission levels while also keeping CO and HC emissions low (Reference 5-14). The program objective was to demonstrate that two combustor designs, the Vortex Air Blast (VAB) and the Jet Induced Circulation (JIC), were capable of low emissions in aircraft turbines at simulated cruise conditions. Jet-A1 fuel was used in both combustors. Ultimately the VAB combustor had lower NO_x emissions, approximately 14 ppmv at 15 percent oxygen under cruise conditions of 5 atmospheres inlet pressure and 833 K (1040°F). The JIC combustor, while giving higher emissions, held promise for further emissions reductions with more developmental work on the fuel preparation and mixing system. Figures 5-8 and 5-9 show the details of the basic VAB and JIC combustors.

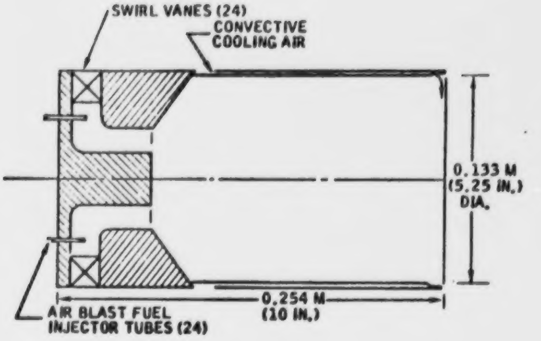
SWIRL VANES (24)
CONVECTIVE COOLING AIR
0.133 M (5.25 IN.) DIA.
0.254 M (10 IN.)
AIR BLAST FUEL INJECTOR TUBES (24)

Figure 5-8. VAB combustor details (Reference 5-7). (Reproduced by permission of the General Electric Gas Turbine Division, GER-2506, 1978, by W.M. Knox.)

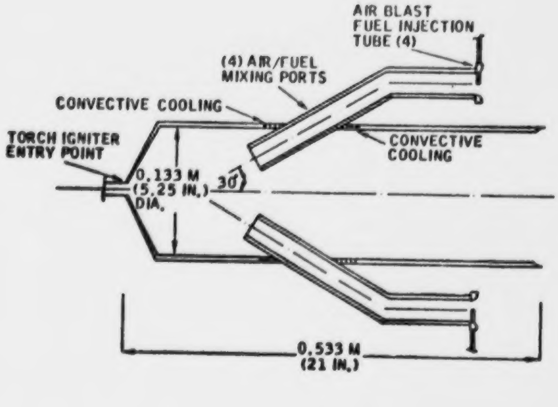
AIR BLAST FUEL INJECTION TUBE (4)
(4) AIR/FUEL MIXING PORTS
CONVECTIVE COOLING
TORCH IGNITER ENTRY POINT
CONVECTIVE COOLING
0.133 M (5.25 IN.) DIA.
30°
0.533 M (21 IN.)

Figure 5-9. JIC combustor details (Reference 5-7). (Reproduced by permission of the General Electric Gas Turbine Division, GER-2506, 1978, by W.M. Knox.)

The baseline (before design modification) emissions versus combustor temperature rise for the VAB combustor are shown in Figure 5-10. Subsequent design changes modified the basic VAB combustor so that ultimately the emissions shown in Figure 5-11 were obtained. Table 5-2 shows the design changes in chronological order and the purpose of each change. The emission values obtained for NO_x, CO and UHC were substantially lower. NO_x was reduced approximately 94 percent from emissions in present day aircraft combustors.

Figure 5-12 presents a review of the various JIC combustor modifications and the effect each had on NO_x emissions. Table 5-3 shows the basic design differences between the baseline combustor and the final design. Further design changes have been recommended for the JIC combustor, particularly with the intent of improving initial fuel distribution.

It should be noted that for both the VAB and JIC combustors, smoke emissions were not detected under all conditions.

In summary, the important program conclusions were:

- Lean burning, prevaporization and premixing concepts have been shown to considerably reduce NO_x emissions from those of conventional aircraft combustors
- Further development work is required to enable the combustors to operate stably over a full range of inlet and loading conditions. Constant geometry premixed combustors are not capable of stable operation over a wide range of inlet and load conditions. Concepts which may improve these problems, such as fuel staging or variable geometry, may significantly complicate aircraft engines
- The VAB combustor obtained NO_x levels of approximately 14 ppmv at 15 percent oxygen
- Although JIC NO_x levels were substantially lowered from conventional combustors, they did not reach the levels attainable with the VAB combustor.
- VAB NO_x emissions, contrary to most designs, did not appear to be pressure dependent.
- Operation of both combustors at low inlet temperatures resulted in rising CO and increased problems with flame stability.

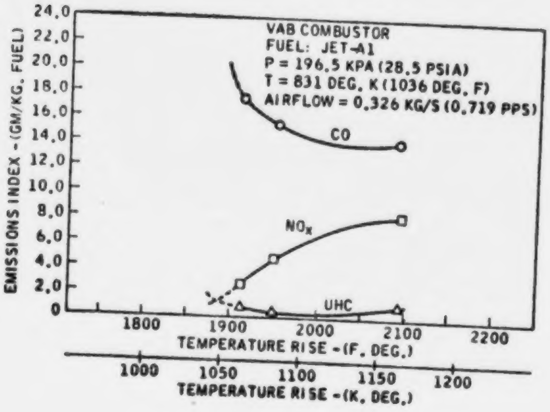

Figure 5-10. VAB combustor test results -- initial configuration (Reference 5-7).
(Reproduced by permission of the General Electric Gas Turbine Division, GER-2506, 1978, by W.M. Knox.)

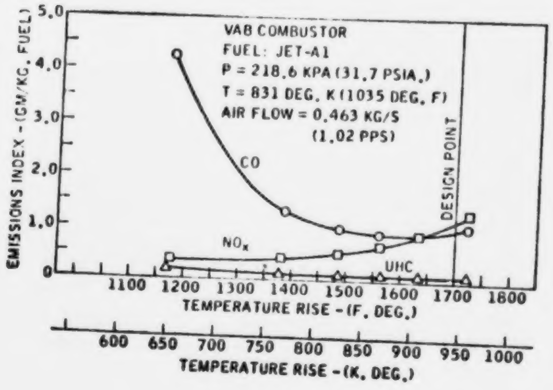

Figure 5-11. VAB combustor test results -- modified fuel injection (Reference 5-7).
(Reproduced by permission of the General Electric Gas Turbine Division, GER-2506, 1978, by W.M. Knox.)

TABLE 5-2. VAB DESIGN MODIFICATIONS

Design Change	Purpose
• Modification of fuel injectors	• Eliminate fuel streaking on swirler walls
• Increased outside diameter of reaction zone	• Improve stabilization characteristics of the combustor
• Increased swirler axial throat length	• Increase premixing through greater residence times
• Increased combustor length	• Provide more reaction time for unburned species (CO + HC)
• Fuel injection modification	• Increase the degree of premixing at the swirler exit by improving the initial fuel distribution

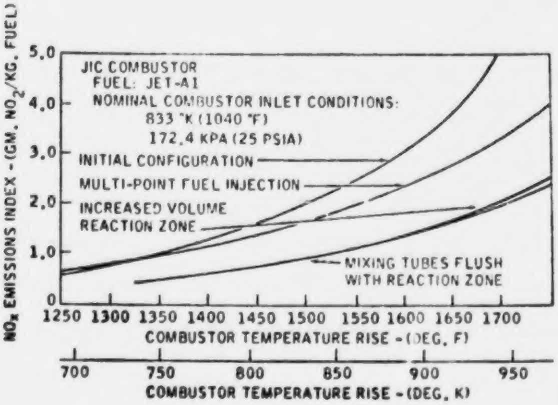

Figure 5-12. JIC combustor NO_x test results (Reference 5-7). (Reproduced by permission of the General Electric Gas Turbine Division, GER-2506, 1978, by W. M. Knox.)

TABLE 5-3. JIC COMBUSTOR CONFIGURATIONS

Item	Initial	Final
Fuel Injection	• Air blast • Mixing tube entry center point • Injection with airflow direction	• Air blast • 13 points on two diameters at each mixing tube entry • Injection against airflow direction
Reaction Zone	Outside diameter = 0.133 m Overall length = 0.133 m	Outside diameter = 0.191 m Overall length = 0.235 m
Liner Cooling	Inter-port cooling strips	Inter-port cooling strips deleted
Mixing Tube	Penetrating into reaction zone	End of mixing tube flush with inside of reaction zone

Problems with off-design operation (i.e., under conditions other than full power), in particular with combustion efficiency, and problems with autoignition and flashback in premixing chambers have arisen in different combustors employing the same concept of lean burning, prevaporization and premixing to obtain a homogeneous firing fuel/air mixture.

Pratt and Whitney Aircraft has conducted a study involving a premixed combustor installed in a high pressure ratio aircraft gas turbine engine (Reference 5-15). This particular design involved a two stage approach whereby at low power, burning at stoichiometric equivalence ratios was done to minimize UHC and CO emissions. At high power, lean equivalence ratios would minimize NO_x production. Figure 5-13 shows a schematic of the staged premixed combustor with the two annular premixing chambers. It also contains 40 primary and 40 secondary fuel injectors.

Three different design airflow distributions were tested, one being a baseline distribution. Four different fuel injection schemes were used as well. A conventional production type combustor was tested for comparison purposes. NO_x emissions versus combustor exit fuel/air

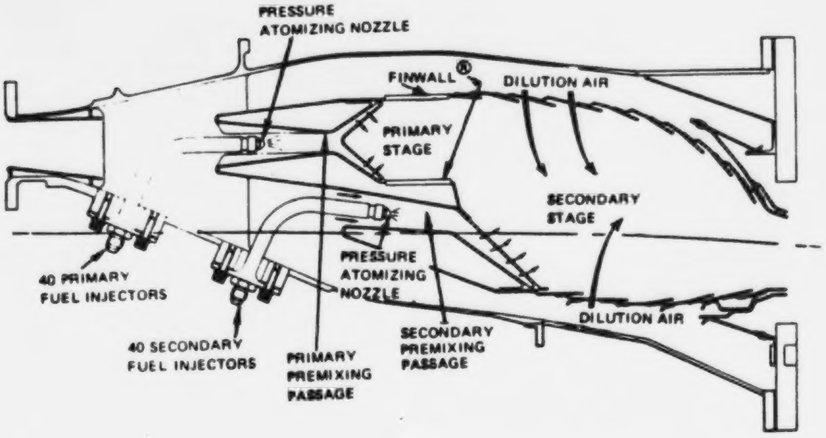
PRESSURE ATOMIZING NOZZLE
FINWALL®
DILUTION AIR
PRIMARY STAGE
SECONDARY STAGE
PRESSURE ATOMIZING NOZZLE
40 PRIMARY FUEL INJECTORS
40 SECONDARY FUEL INJECTORS
PRIMARY PREMIXING PASSAGE
SECONDARY PREMIXING PASSAGE
DILUTION AIR

Figure 5-13. Staged premixed combustor (Reference 5-15). (Reproduced by permission of the AIAA.)

ratios for the conventional and baseline premix airflow distribution are shown in Figure 5-14. Only at high power conditions (high fuel/air ratios), with all injectors firing and with a 1:2 primary to secondary fuel split, are NO_x emissions significantly below emissions from a conventional combustor. NO_x emissions indices for all three airflow distributions are shown in Figure 5-15. Although NO_x emissions for all cases are on the order of one-half of those from conventional combustors, the difference between the three premix configurations is small.

In spite of significant NO_x reduction over conventional combustors (approximately 50 percent), the researchers have recommended no further developmental work with this particular approach. Many difficult problems needed further work, including autoignition in premix chambers, exit temperature distributions, carbon deposits and ignition. However the basic concept of premix appears very promising and should be pursued.

Among the newer techniques being investigated for control of all emissions, as well as more efficient combustion, is catalytic combustion. Gas turbine combustors appear well suited for adaptation to catalytic combustion because of high volumes of excess air and the use of clean fuels such as natural gas and distillate fuels. A number of investigators

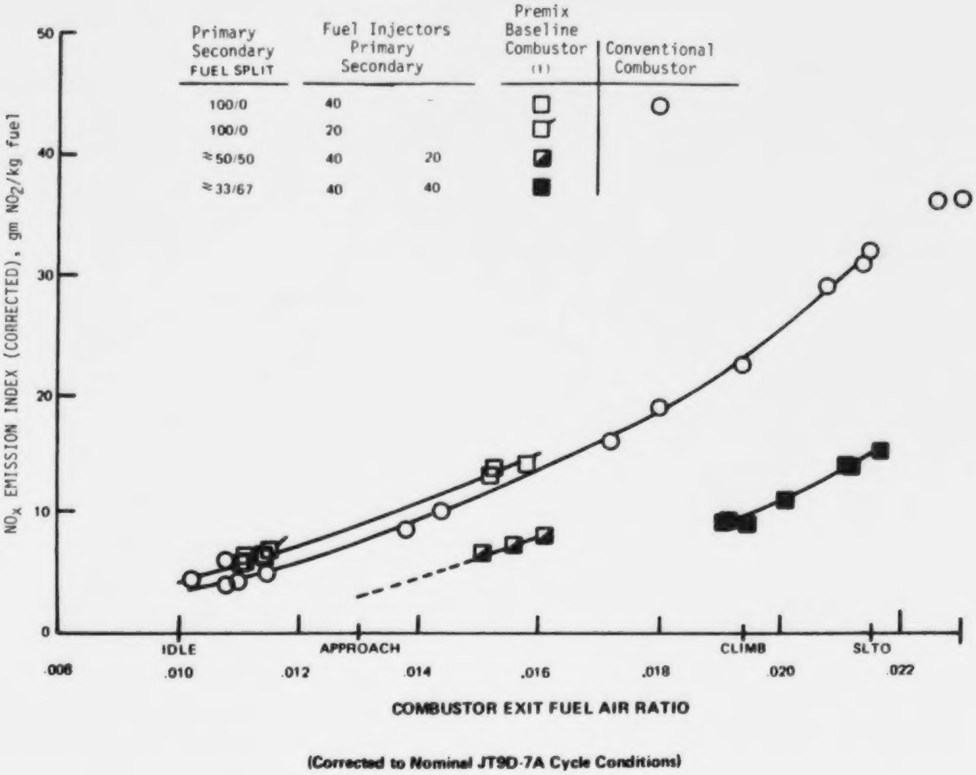

Figure 5-14. NO_x emissions in baseline premix and conventional combustors (Reference 5-15).

(Reproduced by permission of the AIAA.)

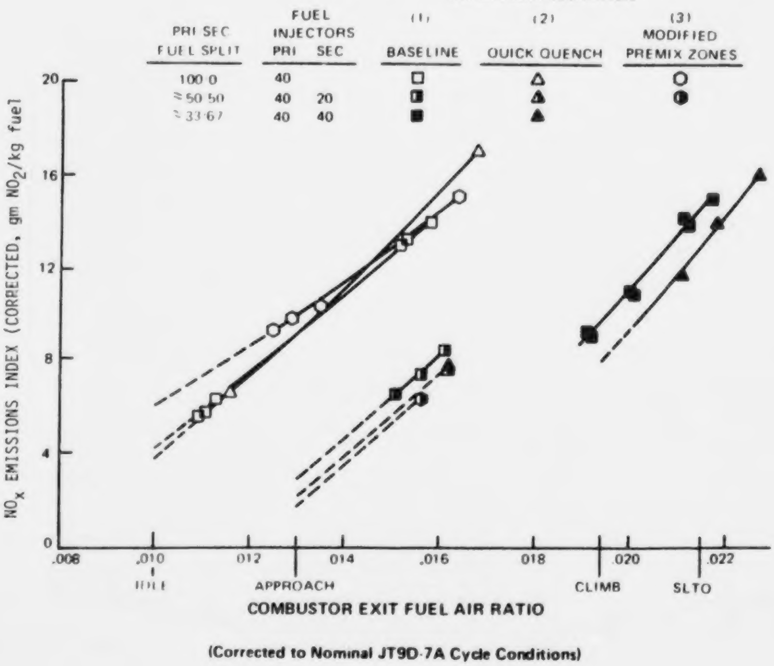

Figure 5-15. NO_x emissions in premix combustor configurations (Reference 5-15).

(Reproduced by permission of the AIAA.)

have studied the application of catalytic combustion to gas turbines and the results are reported in References 5-3 and 5-4. Varying degrees of success in reducing NO_x emissions while simultaneously controlling emissions of unburnt species have been achieved. In one of the more recent programs, Acurex Corporation, in conjunction with General Electric and United Technologies, has made significant advances in development work and is now focusing on solving specific problems before demonstration in a full scale gas turbine combustor. Thermal NO_x produced from catalytic combustion in a number of different catalyst cells versus thermal NO_x produced via thermal combustion is shown in Figure 5-16.

In summary, aside from catalytic combustion, which is still in a relatively early stage of development, superlean primary zone combustion has been one of the main NO_x control concept investigated for use with clean fuels in new combustor designs for existing engines. While some results have been promising, difficulties remain with specific approaches. Problems exist with control over the engine's load range, a need for varriable geometry which causes significant pressure drops, flashback problems in fuel/air premixing tube configurations, and a NO_x pressure dependency. All these problems would be exacerbated by the higher pressure ratios expected with engines of the future.

The Pratt and Whitney Aircraft Group, which screened 26 potential dry NO_x control concepts in an EPA-sponsored study, eventually selected a concept known as the rich burn/quick quench (RBQQ) combustor as the most promising for further development. Figure 5-17 indicates the key components in the experimental combustor employing the rich burning concept. The premix tube premixes and prevaporizes the fuel/air mixture so that a homogeneous rich mixture is burned in the primary zone. No additional air for combustion is provided at this stage. The quick quench slots provide sufficient quantities of air to terminate the fuel rich burning and transform the mixture so it has an overall lean equivalence ratio as it enters the dilution zone. The underlying concept of fuel rich primary burning and quick quency to lean the mixture is not new. However, the particular methods used to test the concept in this experiment have proven extremely effective.

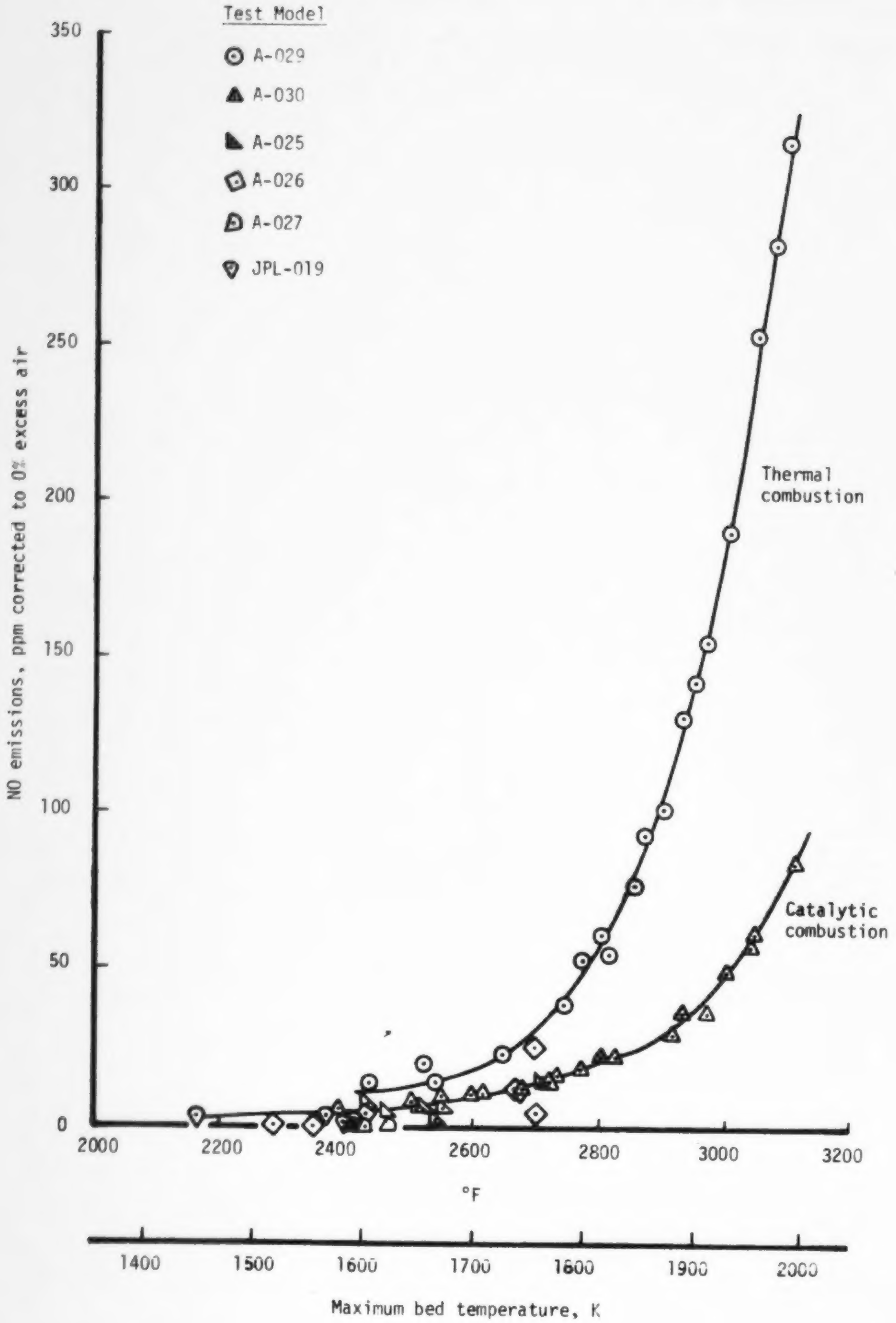

Figure 5-16. NO_x emissions comparison corrected to 0 percent excess air (Reference 5-4).

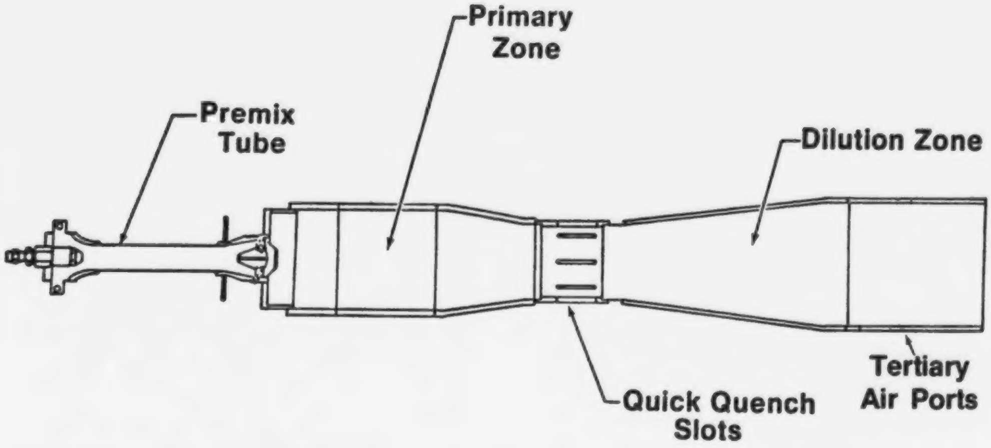

Figure 5-17. Rich burner arrangement (Reference 5-10).

The RBQQ combustor was first tested in a bench-scale configuration. While burning clean #2 fuel; NO_x emissions were extremely low -- as low as 20 ppm. CO was simultaneously low. In addition, the NO versus fuel/air ratio curve stays low and flat once the primary zone becomes rich, and stays flat over the entire fuel-to-air ratio range. Significantly, this indicates that there is no need for variable geometry. Additional results indicate that the RBQQ on clean fuels (and dirty fuels) exhibits no dependency on pressure and, in opposition to conventional thinking, residence time in the primary zone must increase to reduce NO_x.

The RBQQ combustor was then scaled up to a full-size combustor suitable for a 25 MW machine. NO_x and CO emissions continued to be very low, on the order of 40 to 45 ppm over the load range. Emissions of NO_x were not as low as in the bench-scale hardware, however, because of combustor length limitations with the full-scale hardware. NO_x could not be minimized because residence time could not be maximized. Other difficulties with the RBQQ full-scale combustor were flashback in the premix tubes, which were replaced with air-boost nozzles, and some wall temperature problems in the primary combustor zone.

With respect to engines of the future, where pressure ratios and turbine inlet temperatures will rise, the RBQQ combustor seems promising. The RBQQ NO_x emissions are not pressure dependent nor are they dependent on combustor inlet temperature.

5.2.1.4 Dry Control Techniques and Dirty Fuels

If present trends continue, availability and economics may well cause users and manufacturers to consider the use of the less traditional gas turbine fuels. These may include #6 residual, SRC-II, shale oil, low Btu gas, and others. These fuels are higher in impurities such as ash, sulfur, trace metals, and bound nitrogen than are distillate oils. How do the evolving dry NO_x control combustors respond to these fuels?

While super-lean primary zone combustors, such as the Pratt and Whitney staged centertube concept, showed some success with clean fuels, they exhibit significant drawbacks when fired on fuels containing high bound nitrogen. Results from the Pratt and Whitney staged centertube bench-scale testing showed a 90 percent conversion of fuel bound nitrogen when fired on number 2 fuel oil doped to 0.5 percent nitrogen as pyridine. Indications are that this is due to the superlean primary zone maximizing the availability of oxygen.

Catalytic combustion has also been demonstrated in bench-scale hardware to be somewhat effective in controlling fuel NO_x. Acurex Corporation (Reference 5-4) in a two stage catalytic combustor has demonstrated a low 30 percent nominal fuel nitrogen conversion rate to NO_x precursors. The advantages of the two stage arrangement were that the catalytic bed temperatures could be controlled for the purpose of long life and the first stage could be operated fuel-rich to minimize reactions to fuel NO_x. Also, as part of this program, a graded cell catalyst was applied to a model gas turbine combustor. A variety of fuels and pressures were tested and the results are shown in Table 5-4.

Probably the most significant progress with dirty fuels has been made with the Pratt and Whitney-EPA RBQQ concept. The functioning of this concept was discussed in the previous section, so it will not be repeated here.

Figure 5-18 shows the initial results obtained with this control concept. Note that the point of low NO_x (equivalence ratio 0.18) and

TABLE 5-4. MODEL GAS TURBINE DATA SUMMARY: CATALYTIC COMBUSTOR (Reference 5-4)

Test Point	Total Air (%)	Space Velocity (1/hr)	m fuel kg/h (lbm/h)	m air kg/h (lbm/h)	$T_{combustor\ inlet}$ K (°F)	$T_{catalyst\ bed}$ K (°F)	P (atm)	CO (ppm)	NO (ppm)	UHC (ppm)	Fuel
Acurex Tests											
0112-05	~250	91,500	5.13 (11.3)	208.9 (460.3)	651 (713)	1480 (2200)	1.16	0	2	--	Propane
0112-06		96,600	5.68 (12.5)	193.7 (426.7)	657 (724)	1480 (2200)	2.06	0	1	--	
0112-03		87,300	5.13 (11.3)	200.5 (441.7)	700 (801)	1480 (2200)	3.13	0	3	--	
0112-09		92,400	5.40 (11.9)	211.2 (465.3)	703 (806)	1480 (2200)	3.42	0	2	--	
Pratt and Whitney Tests											
1976	312	162,900	7.49 (16.5)	366.1 (806.4)	646 (703)	--	3.06	10	2	0.6	
1977	350	165,800	6.86 (15.1)	373.9 (823.7)	656 (722)	--	4.97	9	1	0.3	Propane
1978	283	167,100	8.44 (18.6)	374.3 (824.4)	650 (711)	--	4.97	10	2	0	
1981	397	185,000	6.75 (14.87)	418.6 (922.0)	657 (723)	--	6.77	110	1	0.3	
1982	504	428,400	12.4 (27.24)	974.7 (2147.0)	716 (829)	--	10.04	23	1	0	
1983	326	141,300	6.24 (13.75)	317.9 (700.2)	632 (679)	--	3.10	9	0	0.6	

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TABLE 5-4. Concluded

Test Point	Total Air (%)	Space Velocity (1/hr)	m fuel kg/h (lbm/h)	m air kg/h (lbm/h)	$T_{\text{combustor inlet}}$ K (°F)	$T_{\text{catalyst bed}}$ K (°F)	P (atm)	CO (ppm)	NO (ppm)	UHC (ppm)	Fuel
Pratt and Whitney Tests (continued)											
1985	860	288,400	5.36 (11.8)	669.7 (1475)	752 (894)	1200[a] (1700)	2.99	1195[b]	3	79.5	No. 2 oil
1986	752	291,900	6.22 (13.7)	677.8 (1493)	756 (901)	1280[a] (1850)	3.03	710	5	34.7	
1987	829	644,000	12.5 (27.5)	1496 (3294)	710 (819)	1280[a] (1850)	5.21	1592	3	23.9	
1988	819	901,100	17.5 (38.5)	2093 (4609)	634 (681)	1140[a] (1600)	7.01	2202	3	222.6	Propane
1989	1277	276,600	3 50 (7.7)	642.4 (1415)	745 (881)	1140[a] (1600)	2.96	1860	44	High	No. 2 oil + pyridine
1991	541	291,900	8.63 (19)	677.8 (1493)	687 (778)	--	3.06	82	145	80.1	
1992	583	564,000	15.4 (34)	1310 (2885)	674 (754)	-- --	5.07	1285	74	24.8	
1993	573	699,500	19.5 (43)	1624 (3578)	670 (746)	--	6.77	1362	68	15.6	

[a] Bed Temperature estimates due to bed nonuniformities.

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[b] High CO and UHC resulted from operating at low bed temperatures to avoid flameholding.

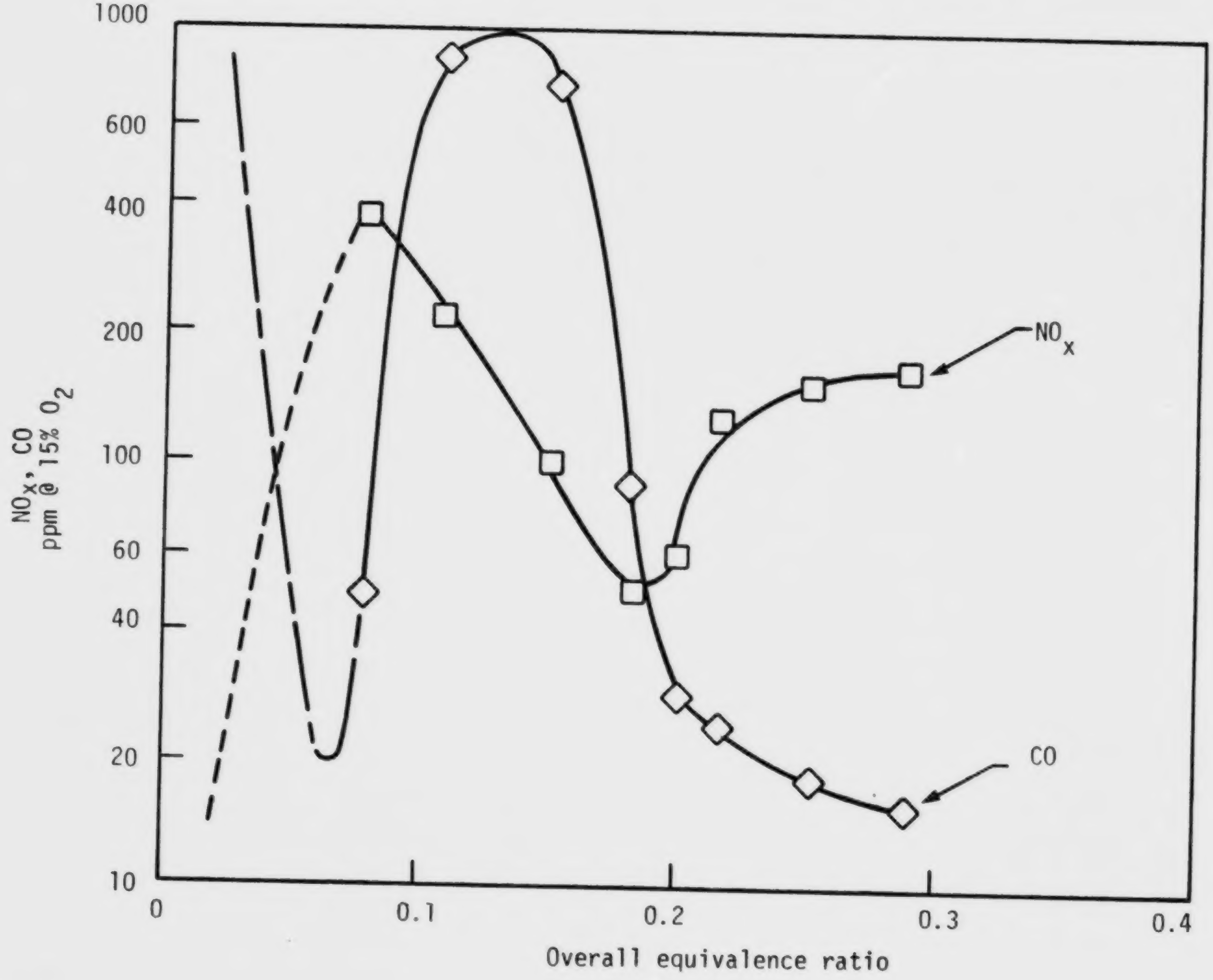

Figure 5-18. Rich burner characteristics, 345 kPa (50 psia), 590K (600°F), 0.5% nitrogen (Reference 5-8).
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the point of high CO (equivalence ratio 0.12) do not coincide. Furthermore, at an overall equivalence ratio of 0.18, indicating fuel rich burning in the primary zone, emissions of NO_x and CO measured only 50 ppmv corrected to 15 percent O_2, substantially below the proposed standard of 75 ppmv at 15 percent O_2 and the program goal of 100 ppm. This was accomplished when burning No. 2 distillate oil containing 0.5 percent fuel bound nitrogen. Although these tests were performed at air pressures of 345^0 kPa (50 psia), and temperatures of 590 K (600^0F) substantially below those encountered in full scale stationary gas turbines, the researchers have obtained similar results at more realistic values of 130^0 kPa (150 psia) and 670 K (750^0F). Apparently the fuel rich/quick quench concept is not subject to the same kinetic constraints that greatly increase NO_x production with lean burning and increasing air temperatures and pressures. Figure 5-19 indicates the results obtained at increased temperatures and pressures which more closely simulate the conditions found in a stationary gas turbine.

Subsequent tests of fuels with bound nitrogen, which involved the use of a variable damper to control primary airflow, were successful in isolating NO_x control from CO control. While NO_x is controlled by primary zone stoichiometry and residence time, secondary zone temperatures appear to control CO. This point is extremely significant because it says that NO_x control does not have to be traded off for CO control.

Another significant characteristic of the RBQQ is that there is a major dependence of NO_x on residence time in the primary zone as shown in Figure 5-20. Surprisingly, the NO_x decreases with the increasing residence time. This relationship, however, proved to be a major limiter to the RBQQ concept in realizing its full potential -- combustor length could not be extended enough to provide the maximum residence time to minimize NO_x. Low emission levels were nevertheless attained.

Tests were subsequently performed in a RBQQ combustor scaled up to fit a 25 MW machine. Operating pressure was 689 kPa (100 psi) and combustor inlet temperatures were up to 589 K (600^0F). A range of turbine inlet temperatures were tested up to a maximum of 1700 K (2600^0F). The fuels tested were SRC II (0.96 percent N), residual shale oil (0.46 percent N), Indonesian/Malaysian residual oil (0.24 percent N), and distillate oil. Tests were run with and without a premix section.

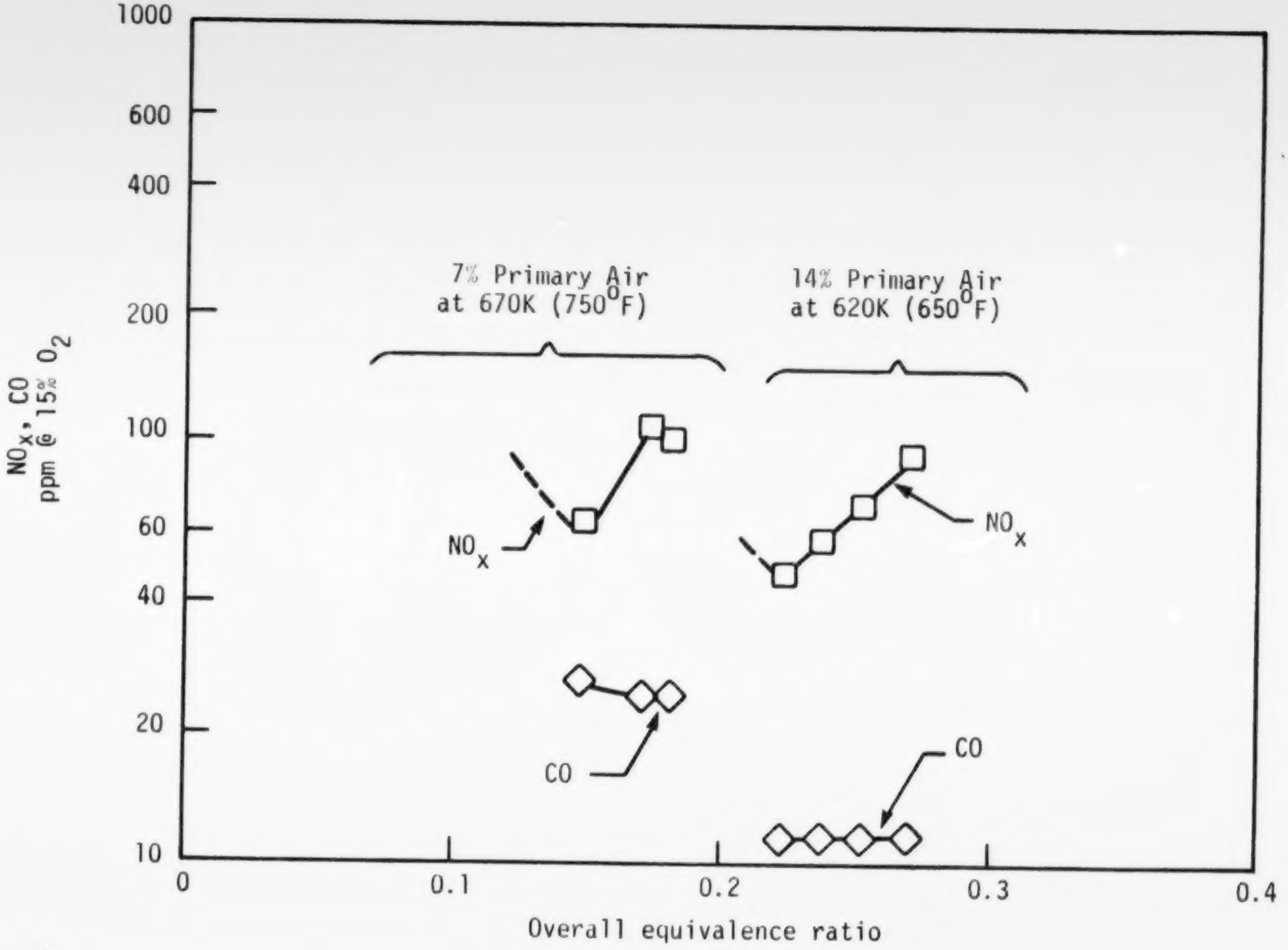

Figure 5-19. Rich burner simulated engine cycle characteristics, 1030 kPa (150 psia), 0.5 percent nitrogen (Reference 5-8).
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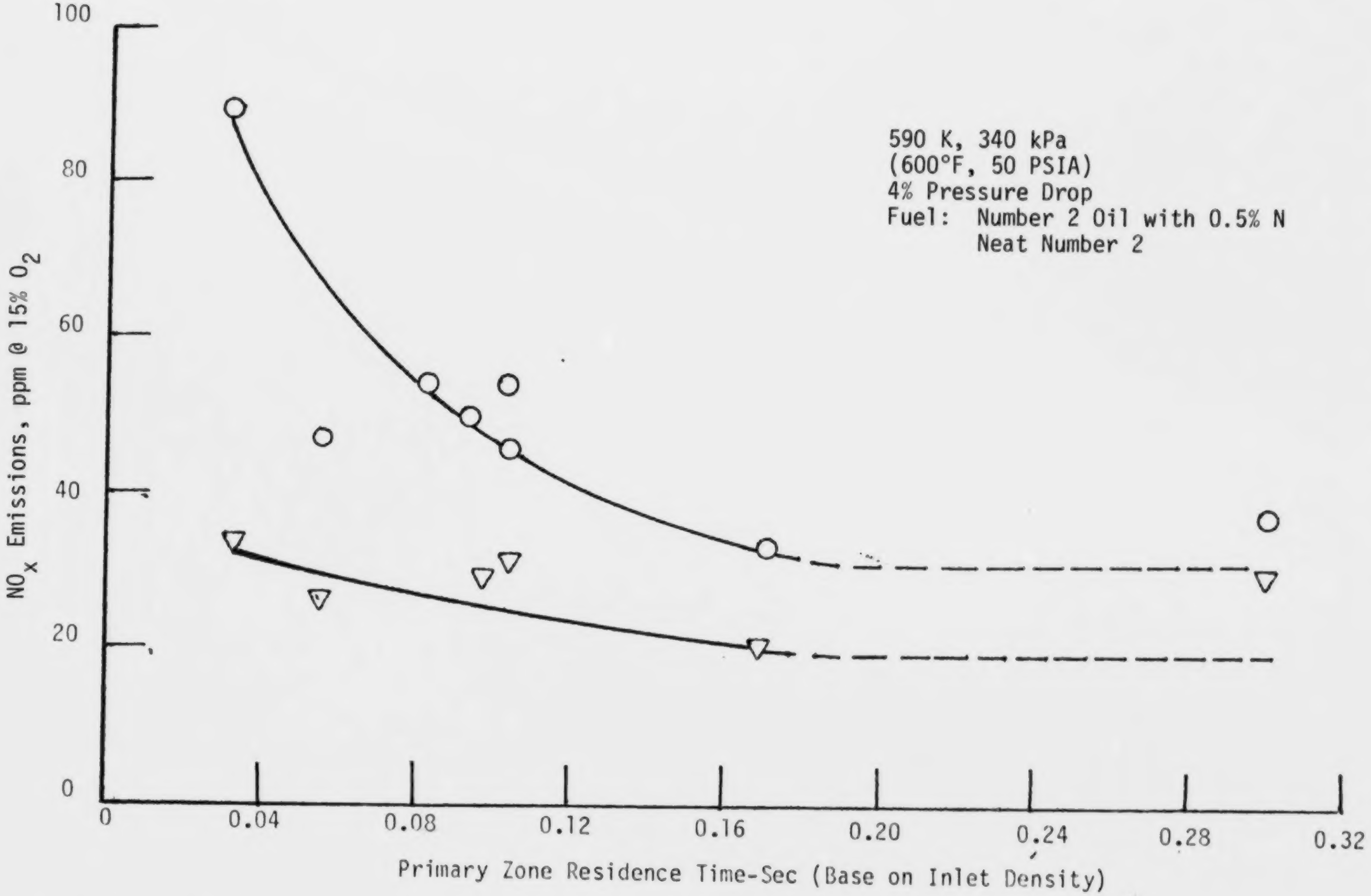

Figure 5-20. Variation of Minimum NO_x Emissions with Primary Zone Residence Time (Reference 5-39).

NO_x emission results (at 15 percent O_2) with the premix xection were 92 ppm for SRC II, 65 ppm for residual shale oil, 75 ppm for Indonesian/Malaysian residual, and 42 ppm for distillate. The same combustor with an air-boost nozzle and a straight swirler on the outside gave NO_x emissions of 80 ppm for SRC II, 65 ppm for Indonesian/Malaysian residual, and 42 ppm for distillate. Residual shale was not burned in this configuration.

Combustor tests without a premix section and turbine inlet temperatures up to 1644-1700 K (2500-2600°F) gave NO_x emissions slightly higher than with premix. However, normal design limits for the primary zone metal temperature were exceeded.

5.2.1.5 Summary

Wet controls for reduction of NO_x from stationary gas turbines are currently the only commercially available techniques. Emissions can easily be reduced to levels below the NSPS by controlling the amount of water or steam injected into the combustor primary zone. Wet controls work well with clean fuels. However, as the amount of fuel nitrogen in the fuel increases, wet controls become increasingly less effective, to the point where they are actually detrimental to NO_x reduction if the percent nitrogen is high enough. Clean fuels, such as distillate oils, are still relatively available, economical, and preferred for gas turbines. But as economics and availability change, users may be put in a position where they must consider dirtier fuels.

While wet controls may be sufficiently effective to reduce NO_x below NSPS levels on fuels containing minimal bound nitrogen, some form of dry controls will be required for dirtier fiels. Furthermore, users would much prefer not to have to deal with the added expense, maintenance, and operation problems attendant with water and steam injection. Thus, it seems clear that dry NO_x controls will replace wet controls within five years. Dry control development seems to be heading in two directions, superlean primary zone combustors for clean fuels and the RBQQ concept for dirty fuels. RBQQ, in particular, appears to show a great deal of promise. NO_x is kept well below the NSPS level despite the presence of fuel nitrogen, while CO is simultaneously kept at a low level. RBQQ has been successfully demonstrated in full-scale hardware on clean and dirty fuels, such as SRC-II and residual shale oil. But further developments are needed in heat transfer problems and the combustor outlet pattern factor.

Superlean combustors are making significant progress with clean fuels, although some problems exist with controls over the load range, premix tube flashbacks, and a pressure dependency which would intensify as pressure ratios increase with future engines.

5.2.2 Incremental Emissions of Pollutants Other than NO_x

The wet and dry NO_x control techniques were discussed in the previous section in terms of their effectiveness in reducing NO_x emissions. However, it must be noted that the same changes that affect NO_x also can affect the other pollutants discharged from the system. If the magnitude of change is ignored, the pollutants may have an adverse effect on the environment. The changes which occur are called incremental emissions. Control of incremental emissions can affect the overall system thermal efficiency and performance. Control of CO and unburned hydrocarbons are an integral part of NO_x control in new combustor designs. Manufacturers are not likely to compromise combustion efficiency for the sake of NO_x control.

The pollutants of concern are the criteria pollutants, CO, UHC, particulate (mass emission rates and particle size distribution), SO_2, and the noncriteria pollutants, sulfates, organics and trace metals. The following subsections present the postulated formation mechanisms of these pollutants and the available data supporting the postulations.

5.2.2.1 Carbon Monoxide and Unburned Hydrocarbons

CO and UHC in combustion product gases results from incomplete fuel combustion. Generally, the conditions which lead to incomplete combustion fall into the following categories:

- Insufficient oxygen available for reaction
- Incomplete fuel/air mixing
- Reduced overall flame temperature
- Decreased combustion gas residence time
- Cold wall impingement (resulting in reduced temperatures)

Any combustion modification which leads to any of the above can result in increased CO and UHC emissions.

Thus, some increase of CO and UHC with water injection may happen. The heat required to vaporize the water, as well as dilution effects, tend to impede combustion and result in lower combustor temperatures. This can lead to reduced combustion efficiency and increased CO and UHC emission levels. It is postulated that steam injection will also increase CO and UHC emission levels, but to a slightly lesser degree due to the smaller heat load required for vaporization.

Documented effects of water injection on CO emissions from gas turbines are shown in Table 5-5. There appears to be only a slight trend toward increased CO emissions with water injection for distillate and diesel oil firing. However, the significant CO increase for natural gas firing may be of concern, but it should be noted that the data are very limited.

Unburned vapor phase hydrocarbon emissions from combustion sources are of environmental concern because of their role in the atmospheric reactions leading to photochemical smog. These hydrocarbons include aliphatic, oxygenated, and low molecular weight aromatic organic compounds which exist in the vapor phase of flue gas at noncondensing temperatures. Thus these hydrocarbons include such organic compounds as alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes.

Like CO emissions, unburned hydrocarbon emissions are a function of combustion completeness. Therefore, since water injection NO_x control tends to impede complete combustion, hydrocarbon emissions can be expected to increase with increasing water injection. Table 5-6 presents the limited data available. Though not conclusive, a general trend towards slightly increased unburned hydrocarbons is noted.

The documented effects of dry NO_x controls on CO and UHC emissions appear to indicate that both superlean combustors and the RBQQ combustor are capable of minimizing unburned pollutant species to acceptable levels. There are, however, qualifications. For superlean configurations, CO and UHC emissions can be minimized if the engine control system is properly executed so that in response to high temperatures, the gas stream is not overquenched, causing a rise in CO and UHC. In addition, any deterioration in components could affect combustion efficiency, thereby inducing CO and UHC formation. Figure 5-21 shows the characteristic "scissors" curve of CO and NO_x in a superlean bench-scale

TABLE 5-5. EFFECT OF WATER INJECTION NO_x CONTROL ON CO EMISSIONS FROM A GAS TURBINE (References 5-3)

Fuel	CO Emissions (ppm)[a]	
	Baseline	Water Injection
Natural gas	147 252	1,134 1,512
Distillate oil	17 1,174	22 1,286
Diesel	99 135 93	144 162 30

[a] At three percent O_2, dry basis.

TABLE 5-6. EFFECT OF WATER INJECTION NO_x CONTROL ON UHC EMISSIONS FROM A GAS TURBINE (References 5-3 and 5-23)

Fuel	UHC Emissions (ppm)[a]	
	Baseline	Water Injection
Natural gas	234 141 36	372 246 27
No. 2 Distillate oil	8	10
Diesel	24	12

[a] At three percent O_2, dry basis.

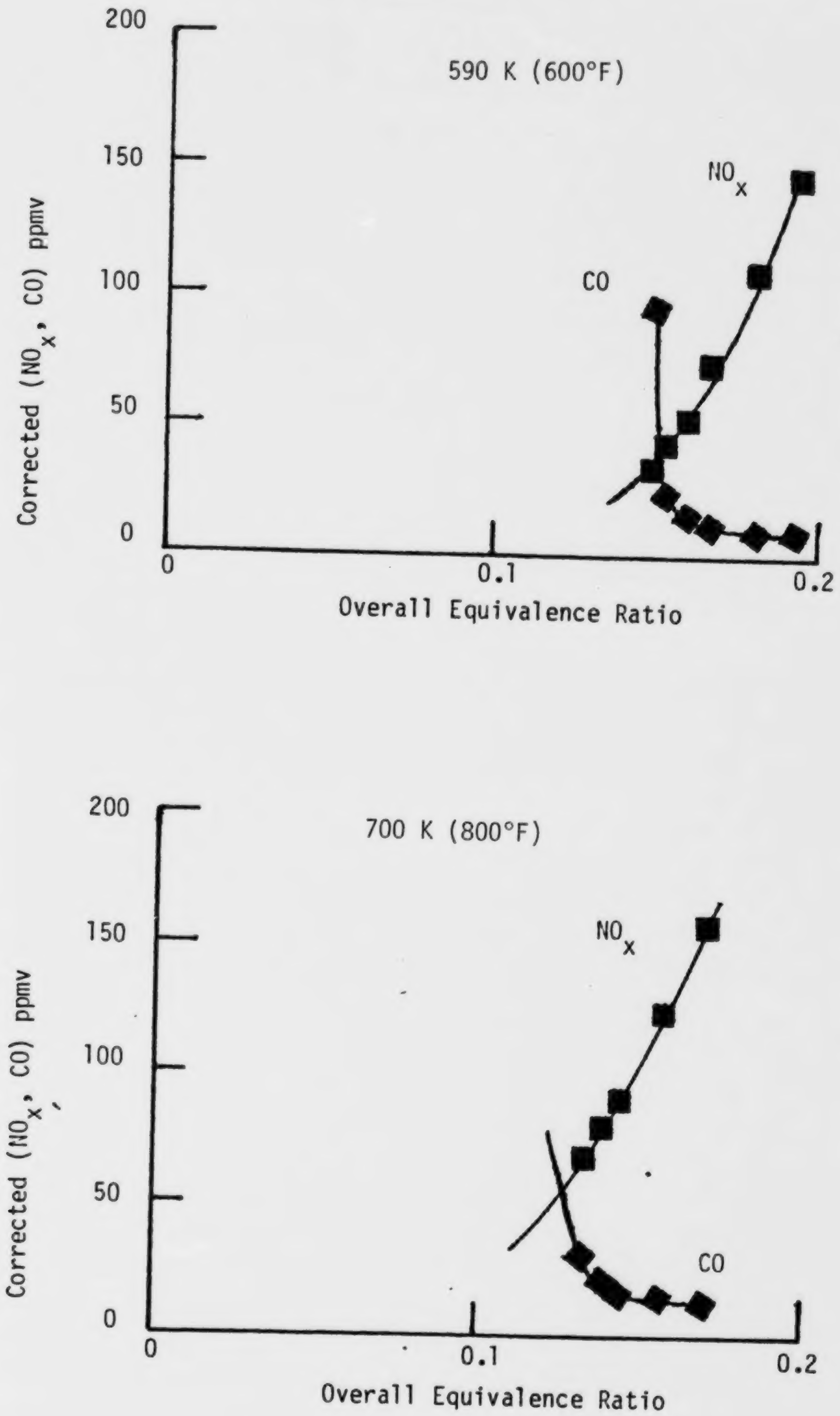

Figure 5-21. Lean burner high pressure characteristics, 689 kPa (100 psia) (Reference 5-16)

combustor (Reference 5-10) at two inlet temperatures while burning clean fuel. Due to the steep slope of the CO curves, any change in fuel/air ratio, caused by such things as an improper control system response or component wear, can cause significant increases in CO. UHC would respond in a similar manner.

The Pratt and Whitney-EPA RBQQ combustor is able to limit CO and UHC while minimizing NO_x by careful control of airflow in the primary zone and temperature in the secondary zone. Figure 5-22 shows results from bench-scale results where low NO_x concentrations have been obtained over a range of overall equivalence ratios while CO remains constant (the dashed line are values obtained at a lower overall air flow rate). These results are extremely significant because NO_x control and CO control are isolated from each other. Results from full-scale tests were not quite as successful. While NO_x remained low, CO increased due to a considerably shortened combustor and a revamped secondary mixing pattern. If combustor length, and thus residence time, could be increased and secondary temperatures could be held high enough, minimizing CO should be no problem.

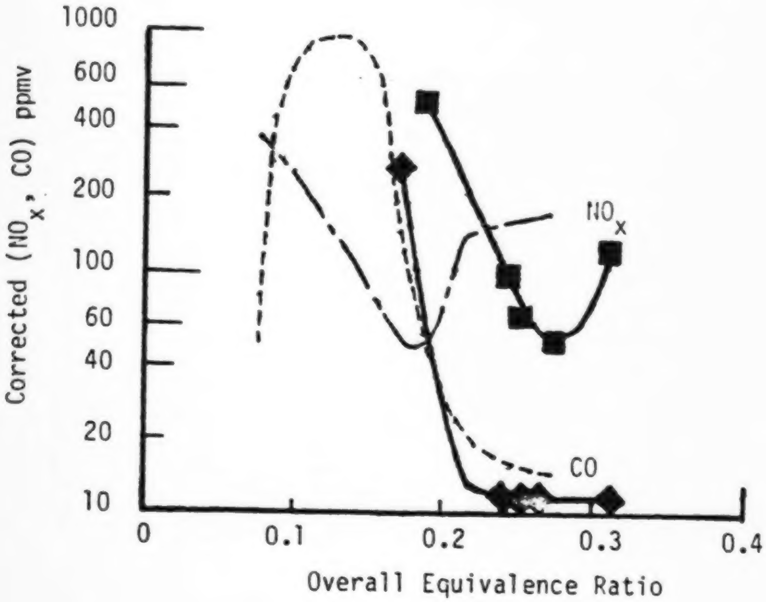

Figure 22. Effect of staged combustion and fuel rich combustion on NO_x and CO emissions (Reference 5-16).

5.2.2.2 Particulate Emissions

Although gas-fired units produce negligible amounts of particulate, distillate fuel oil and "dirty" oils such as residual oil can emit significant concentrations of particulate (Reference 5-17). Therefore the impact of NO_x control techniques on particulate emissions can be of concern.

The formation of particulates in a combustion source is intimately related to combustion aerodynamics, the mechanisms of fuel/air mixing, and the effects of these factors on combustion gas temperature-time history. The optimum conditions for reducing particulate formation (intense, high temperature flames as produced by high turbulence and rapid fuel/air mixing) are not the conditions for suppressing NO_x formation. Therefore, most attempts to produce low NO_x combustion designs have been comprised by the need to limit formation of particulates or smoke (Reference 5-18).

Particulate emissions from oil-fired gas turbines can be composed of soot (condensed organic matter) and ash (incombustible mineral matter). Thus, particulate mass emissions are generally a function of the completeness of combustion given that the ash content of emitted particulate solely depends on the ash content of the fuel burned. When controls for NO_x that reduce combustion efficiency are applied, an increase in condensible organic matter (soot) can be expected.

The data on particulate emissions from gas turbines using wet controls are very limited and contradictory. The effect of water injection appears to be related to the specific injection method used and on load. The manner in which particulates vary as wet controls are applied, is, in general, similar to the effect on CO and HC emissions. The same conditions which promote oxidation of CO and HC also promote oxidation of filterable (carbon soot) and condensable (heavy hydrocarbons) particulate matter. One may therefore expect a decline in combustion efficiency to increase amounts of particulate emissions. The available data, however, do not support or refute this conclusion.

The data on particulate emissions from gas turbines resulting from applied dry NO_x controls are also very limited. However, the available data indicate that incremental particulate emissions from NO_x controls follow trends similar to those for incremental CO and hydrocarbon emissions.

Figure 5-23 shows the effect of turbine load on particulate emissions. Like CO and HC emissions, particle emissions increase as turbine load is reduced. As the figure shows, particulate emission increases average 40 percent when turbine load is decreased to 30 percent of rated capacity.

5.2.2.3 Sulfates

Ambient sulfate levels are a matter of increasing concern in regions with large numbers of combustion sources firing sulfur-bearing coal and oil (notably, the northeast region of the U.S.). Although the direct health effects of high ambient sulfate levels are currently unclear, high sulfate aerosol concentrations are known to decrease visibility and aggravate acid precipitation phenomena.

Ambient sulfates are comprised of directly emitted sulfates (primary sulfates) and those derived from the atmospheric oxidation of SO_2 (secondary sulfates). SO_2 arises from the sulfur contained in the fuel. Essentially all sulfur entering the combustor is discharged as SO_2. The primary concern for incremental emissions, then, is to control the ratio of primary sulfate to SO_2 (SO_4/SO_2). The sulfate present may exist as either sulfuric acid (H_2SO_4) or as metal or ammonium sulfates. The potential for internal corrosion in gas turbines from sulfates is great, and thus unacceptable. Consequently the sulfur content of the fuel is controlled.

The low concentrations of sulfur in the primary gas turbine fuels and the normally high operating efficiency of gas turbines have resulted in little concern for the level of these emissions. Data showing the effects of wet controls on sulfate levels are extremely limited. However, results from a recently completed test program performed on a 60 MW utility gas turbine equipped with water injection indicated that the NO_x control technique had no significant effect on SO_2 or SO_4 emissions (see Section 6.1).

5.2.2.4 Organics

Organics are defined as those organic species not included in the criteria pollutant class of unburned vapor phase hydrocarbons. These remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can generally be classed into a group known either as polycyclic organic matter (POM) or polynuclear aromatic hydrocarbons (PNA or PAH) (References 5-18 and 5-19).

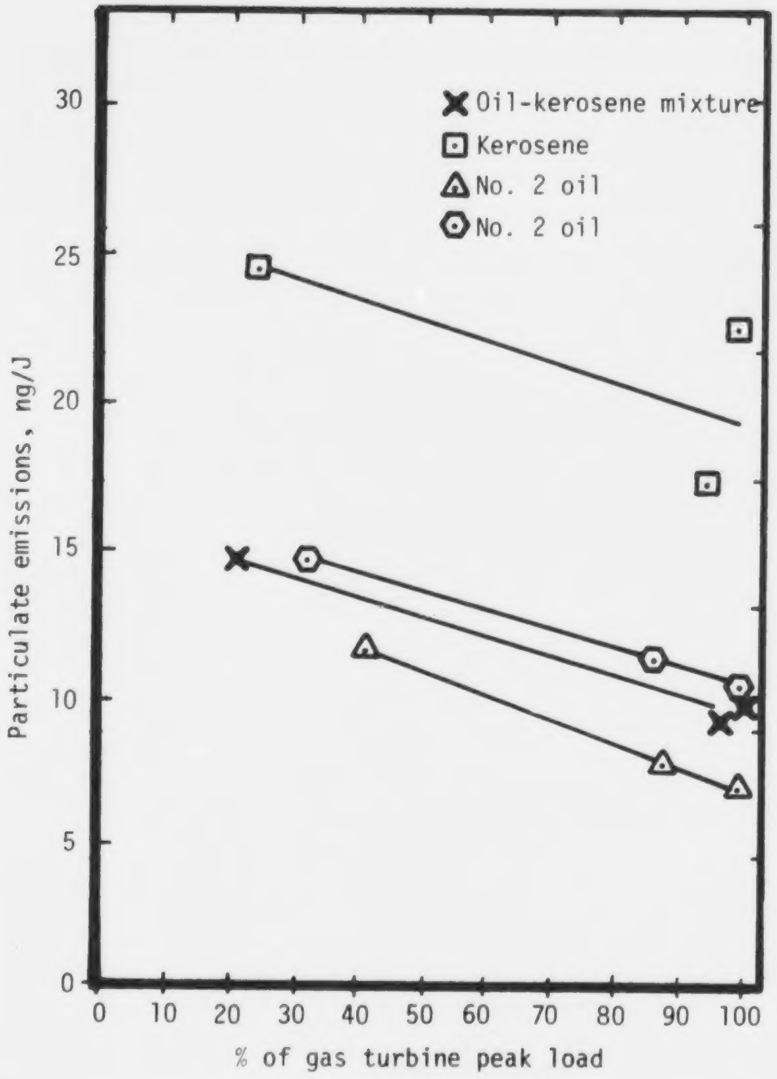

Figure 5-23. Gas turbine particulate emissions as a function of load (Reference 5-3).

POM emissions have significant environmental impact because several species are highly carcinogenic (Reference 5-19). The fact that they generally exist as fine particulate makes them an even more serious health hazard.

Although polycyclic organic matter can conceivably be formed in the combustion of any hydrocarbon fuel, it is considered more of a problem when associated with soot (carbonaceous particulate) emissions from coal- and oil-fired combustion equipment. Thus, POM production is of only minor concern in gas-fired gas turbine systems and of some concern in oil-fired systems.

5.2.2.5 Trace Elements

Emissions of trace metals are generally a concern only from combustion sources firing coal and residual oil. They are a lesser problem in oil-fired gas turbines since these sources tend to fire distillate fuels, although present trends indicate an eventual shift to coal derived synthetic fuels. Trace metal concentrations in distillate oils are generally much lower than those in residual oils and synthetic fuels. This, coupled with the fact that fuel specifications limit the level of certain trace elements in the fuel fired, suggest that trace element emissions from gas turbines should present no problems under either controlled or uncontrolled operation.

5.2.2.6 Summary of Incremental Emissions

CO and UHC are products of incomplete combustion and result from dropping temperatures too rapidly. An engine at idle and low power will produce high CO and UHC because combustion efficiency is low. Full load produces high combustion efficiencies and therefore low CO and high UHC. While data demonstrating the effect of NO_x controls on CO and UHC emissions is limited, trends seem to indicate that water and steam injection tend to increase these emissions. Dry controls, such as superlean and RBQQ both appear to be capable of minimizing CO and UHC, but each type of combustor has its limitations that need to be corrected before they become commercially available.

5.2.3 Incremental Costs of NO_x Controls

The pollutants of concern with stationary gas turbines are primarily NO_x, CO and UHC. NO_x is the major pollutant from gas turbines; CO and UHC are already controlled for efficiency reasons.

CO and UHC are emitted in small quantities and SO_2 emissions, emitted in quantities directly proportional to fuel sulfur content, is best controlled by regulating the amount of fuel sulfur. Gas turbines put out a large amount of gas due to the very large excess air requirement. This causes the cost of SO_2 flue gas scrubbers to be prohibitively high (Reference 5-3). The proposed SO_2 emission standard for gas turbines limits either SO_2 exhaust emission levels or sulfur in the fuel. Since the sulfur content of most distillate oil is below the standard of 0.8 percent, there should be no problem as long as distillate oil is burned. Burning residual oil could present more of a problem, but it has been estimated that 85 percent of all residual oil is below 0.8 percent sulfur (Reference 5-3). There will be a cost if users are forced to analyze their fuel for sulfur on a daily basis, especially when the turbines are used in remote areas. However, except for remote areas, this cost should be small. In any event, it appears that the sampling requirement may be modified where it would cause undue hardship (Reference 5-20).

The following sections detail estimates of NO_x control costs. In estimating the equipment and operating cost of NO_x controls, there has been some limited operating experience with water and steam injection on large utility size turbines. For the smaller size turbines, there has been very little operating experience with wet controls. Therefore the costs given for the smaller units may not be as accurate as the costs for the utility size units.

This report uses the same costs and procedures as in the SSEIS report on gas turbines. However, the costs reported here have been updated from user experience collected since the SSEIS was published. Wet controls are discussed first and then dry controls. Since costs are site dependent, the costs given can only be considered typical, not the exact cost estimate for a particular site. As discussed above for sulfur, it is assumed that costs required for fuel analysis will be minimal.

5.2.3.1 Wet Controls

This section describes the costs associated with wet methods for controlling NO_x emissions from gas turbines. It will be assumed that water will always be available. Since the proposed standard will probably be modified where there is a limited water supply (Reference 5-20), this seems a reasonable assumption. As in the SSEIS report, it will be assumed that there are no additional costs due to water pollution problems. Wastes are produced when the water purification systems that are used for the water injection systems are cleaned or recharged, but there should be few problems in disposing of this waste. This is especially true for utility installations which already have to purify large amounts of boiler feedwater as well as dispose of the wastes. In many cases the existing sewer system should be able to handle the wastes produced. One user reported trouble with the waste from recharging the purifiers (Reference 5-21) but that was due to lack of experience with the equipment rather than inherent system problems.

In the following subsections, costs are first given for utility size and then smaller size units. Since information on wet controls for the smaller size turbines is limited, small and medium size turbines are combined.

Utility Turbines

For wet controls on utility size turbines, the most expensive cost is for the water purification system. The water injected into the turbine must be very clean to prevent damage to the turbine. Utility plants have systems for supplying water to their boilers. If there is enough excess capacity, then the cost for the water purification system can be lessened. This was not assumed in the cost analysis, so it might be possible to obtain a lower cost than listed below. No costs are given for steam generating equipment because steam injection would only be used with a combined cycle plant where there is an existing source of steam.

The following three tables list costs for water and steam injection systems as quoted by users. Table 5-7 lists 1973 costs reported by San Diego Gas and Electric to control their gas turbines (Reference 5-22). The turbines themselves cost about $100/kW in 1973. Also, since these costs are for utility use, the turbine cost also includes the cost of the electric generator. Tables 5-8 and 5-9 list costs quoted by the City of Pasadena, California Power and Water Department and the City of Glendale, California, Public Service Department, respectively (References 5-23 and 5-24). The cost for the water injection equipment averaged 5 to 10 percent of the cost of the turbine itself. Based on Tables 5-7 through 5-9, a

TABLE 5-7. 1973 WATER INJECTION INVESTMENT COST (SAN DIEGO GAS AND ELECTRIC) (Reference 5-22)

Control System	Gas Turbine Size		
	20 MW	49 MW	81 MW
Combustor modifications including water injection nozzles	$1.00/kW	$0.86/kW	$1.04/kW
Water injection pumps and water control system	$3.54/kW	$2.88/kW	$3.10/kW
Associated piping and water storage facilities	$1.72/kW	$1.05/kW	$0.87/kW
Water treatment equipment	$0.90/kW	$0.47/kW	$0.47/kW
General expenses including engineering, administration, testing, taxes	$1.15/kW	$0.82/kW	$0.57/kW
TOTAL	$8.31/kW	$6.07/kW	$6.05/kW

TABLE 5-8. 1975 WATER INJECTION COST (CITY OF PASADENA) (REFERENCE 5-23)

Cost Item	Cost for Two 26 MW Units
Water purification system	$100,000 ($50,000/turbine)
Other costs	$50,000
Total per turbine	$100,000
Cost/kW	$3.85

TABLE 5-9. WATER AND STEAM INJECTION COSTS
(CITY OF GLENDALE, Reference 5-24)

Water injection costs (equipment only) (1973)	
$300,000 out of $3,500,000 for 31 MW	= $9.68/kW
Steam injection costs (equipment only) (1976)	
$1,000,000 out of $20,000,000 for 120 MW combined cycle (gas turbine produces 90 MW)	= $8.30/kW

1978 cost of $10/kW appears appropriate for the water injection system. The SSEIS (Reference 5-3) used a figure of $2.58/kW in 1975 dollars. However, since the water injection systems listed in the SSEIS were installed around 1975, this figure appears too low. Energy and Environmental Analysis (EEA) has reevaluated water injection costs for the EPA and has given an estimate of $7/kW for a 60 MW gas turbine (Reference 5-25). Thus, it has been decided to use $10/kW, in 1978 dollars, in the present analysis. Even so, for some installations, even this figure might be too low. San Diego Gas and Electric is now estimating that it will cost $23/kW to convert an existing 32 MW gas turbine to water injection (Reference 5-26).

Assigning typical incremental operating and maintenance costs as a result of wet NO_x controls is a more difficult task. Section 6.5 covers the changes in operations and maintenance due to the wet controls. As described there, it is unclear if there is any significant increased maintenance due to the water injection other than the maintenance for the water system itself. Therefore it will be assumed that there is no increased maintenance cost for the turbine due to the water injection system. From data compiled on operating and maintenance costs for turbines (References 5-27, 5-29, 5-30), a figure of 3 percent of installed costs per year appears more reasonable than the one percent used in the SSEIS (Reference 5-3). A fixed charge of 20 percent of installed costs per year will be used, the same value used in the SSEIS report.

The greatest operating cost impact due to wet controls results from the fuel penalty caused by lowered thermal efficiency. Estimates of the drop in thermal efficiency range from zero to five percent (References 5-3, 5-23, 5-28, 5-31, 5-32). A figure of two percent, an approximate average, is used in the calculations. There is also an increase in power output of the turbine due to water injection. It will be assumed that the utility company can use this increased capacity and a capital charge credit of two percent will be used. A figure of $\$0.79/m^3$ is used for the cost of the water, which agrees with the SSEIS report (Reference 5-3) and one user's experience (Reference 5-23). A figure of 10.9 MJ/kWh is used for the heat rate of a simple cycle gas turbine. This value was also used in the SSEIS report. In actual practice, most existing turbines have heat rates of 12.7 to 16.9 MJ/kWh (References 5-27, 5-29), although new turbines are expected to be operating at the lower heat rates (Reference 5-32).

The turbine is assumed to be operating on No. 2 oil at a cost of \$2.84/GJ (Reference 5-33). Table 5-10 estimates the cost of electricity from an uncontrolled turbine. Table 5-11 estimates the increased costs due to the water injection system. Based on the costs cited in Table 5-12, it is estimated that water injection will increase the cost of electricity by 4 percent from a peaking unit, 2.7 percent for a midrange unit and 2.6 percent for a base load unit.

Smaller Gas Turbines

For turbines smaller than utility size, there has not been any known long term use of water injection. Therefore, there are no operating data to base the costs on. The same assumptions that were made for utility size turbines when calculating the costs will be made for the smaller units. Any significant changes are noted. Gas turbines in pipeline service operate unattended (Reference 5-34), thus costs associated with these applications will be estimated assuming unattended operation. One utility operator was able to let his turbine run unattended except for recharging the water purification system (Reference 5-28). It is reasonable to expect that when the pipeline gets its weekly check, the water system could also be checked.

In calculating the operating costs, the following changes in the assumption used for utility turbines were made. A heat rate of 12.5 MJ/kWh (13,200 Btu/kWh) and a maintenance and operating charge of

TABLE 5-10. ESTIMATED OPERATING COST OF UNCONTROLLED UTILITY GAS TURBINE (50 MW), 1978 DOLLARS

Use	Peaking	Midrange	Baseload
Installed cost (\$/kW)	150	150	150
Heat rate (MJ/kWh)	10.9	10.9	10.9
Fixed costs (% of installed cost)	20	20	20
Operating and maintenance (% of installed cost)	3	3	3
Fuel cost (\$/GJ)	2.84	2.84	2.84
Costs			
Fixed, operating, and maintenance mills/kWh)	69	8.6	4.3
Fuel (mills/kWh)	30.9	30.9	30.9
Total (mills/kWh)	100	40	35

TABLE 5-11. ESTIMATED COST OF WATER INJECTION FOR UTILITY GAS TURBINES, 1978 DOLLARS

Use	Peaking	Midrange	Baseload
Size (MW)	50	50	50
Hours of operation per year	500	4000	8000
Water costs (\$/m^3)	0.8	0.8	0.8
Water feed rate (m^3/h)	7.6	7.6	7.6
Installed cost (\$/kW)	10.0	10.0	10.0
Annualized costs (mills/kWh)			
Fixed, operating, and maintenance	4.6	0.6	0.3
Water cost	0.1	0.1	0.1
Fuel penalty	0.6	0.6	0.6
Capacity enhancement	-1.3	-0.2	-0.1
Total (mills/kWh)	4.0	1.1	0.9
% change over uncontrolled	4.0	2.7	2.6

TABLE 5-12. ESTIMATED COSTS FOR UNCONTROLLED INDUSTRIAL GAS TURBINE, 1978 DOLLARS

Use	Midrange	Baseload
Size (kW)	2775	2775
Installed cost ($1/kW)	300	300
Heat rate (MJ/kWh)	14	14
Fixed costs (% of installed cost)	20	20
Operating and maintenance (% of installed cost)	5	5
Fuel cost ($/GJ)	2.84	2.84
Hours per year operation	4000	8000
Annualized costs (mills/kWh)		
Fixed, operating, and maintenance	18.75	9.38
Fuel	39.8	39.8
Total	59	49

5 percent were used, in agreement with the SSEIS. There is a wide difference between costs quoted for the water injection system between EPA's estimates in the SSEIS report, $7.50/kW (Reference 5-3) and two manufacturers, $30/kW (Reference 2-35) and $35/kW (References 2-36 and 2-37). The SSEIS prices are based on estimates made in 1974 by manufacturers while the process was still in the development stage for large turbine applications. For the present report, a cost of $30/kW will be used as the cost of wet controls for a typical 2.8 MW unit. Costs are only given for a 2.8 MW unit because, except for the very small units, they all have about the same cost per kW. Table 5-12 shows the costs for 4000 and 8000 hour operation while Table 5-13 shows the increased cost due to water injection. The total cost of the turbine depends on how it is used (i.e., for generation, pumping, compressing, etc.). A cost of $300/kW is used but depending on application, this cost can be significantly higher. Water injection causes an increased charge in kWh

TABLE 5-13. ESTIMATED COSTS OF WATER INJECTION FOR INDUSTRIAL GAS TURBINE, 1978 DOLLARS

Use	Midrange	Baseload
Size (kW)	2775	2775
Installed costs ($/kW)	30	30
Hours per year operation	4000	8000
Water cost ($/m^3)	0.8	0.8
Flowrate (m^3/h)	0.4	0.4
Annualized costs (mills/kWh)		
Fixed, operating, and maintenance	1.87	0.94
Fuel penalty	0.80	0.80
Water costs	0.10	0.10
Total (mills/kWh)	2.8	1.8
% of uncontrolled	4.7	3.7

delivered of 4.7 percent for a 3 MW unit and 3.7 percent in a 6 MW unit. No credit is taken for increased capacity.

5.2.3.2 Dry Controls

Since dry controls are still in the developmental stages, the costs cannot be accurately estimated and only rough estimates are possible. One manufacturer of utility size turbines (Reference 5-32) hopes to design a new type of combustor liner to replace existing liners. They hope that no new air or fuel controls would be needed and no additional maintenance would be required. If they are successful, the only additional costs would be the development costs. Since combustion liners are routinely changed every several years, a large base is provided to spread development costs over. Thus, dry controls for utility boilers will probably be cheaper than wet controls, though this statement is based on unproven results.

For smaller turbines, one manufacturer (Reference 5-37) estimated equipment costs for dry controls to be as high as those for wet controls. This is partly due to the small market for 3000 kW turbines, consequently there is a small base for spreading development costs over. They estimated a cost of $95,000 for dry controls for turbines in the 3 MW range. Another manufacturer (Reference 5-38) has estimated that the cost of dry controls to the customer will be small. Large development costs could, however, force this manufacturer out of the American market. A full scale turbine with dry controls to meet the proposed NO_x NSPS has not yet been built so these costs are only rough estimates. Since there should be no fuel penalty with dry controls, operating costs and cost per kWh generated should be less than for wet controls. Using the same figures given in Table 5-13 but subtracting out the fuel penalty, for 4000 hours per year operations, there would be a 3.4 percent increase in the cost of power delivered. For 8000 hour/year generation, there would be a 2.1 percent increase in the cost of power delivered.

5.3 REGIONAL CONSIDERATIONS AFFECTING CONTROL SELECTION

Regional considerations refer to situations or conditions external to turbine operation which could adversely affect the operation of NO_x control equipment, limit the degree of control or have a significant impact on control costs. The following section discusses the types of problems that one must consider when evaluating various control alternatives. Fuel and equipment specific considerations are treated separately.

5.3.1 Fuel Considerations

As discussed in Section 4, the composition of the fuel burned in the gas turbine will have a large impact on the emission rate of NO_x. The fuel composition also determines to a great extent the emission rate of SO_x, particulate, and trace metals.

A potential partial solution for meeting the New Source Performance Standards could be fuel switching. Generally fuel changes would be from a "dirty" high pollutant potential fuel, to a "clean" low nitrogen, low sulfur fuel. Fuel switching generally is an economic consideration; substituting a more highly processed, higher cost fuel for a "dirty" low cost fuel. The primary regional consideration would be the availability of distillate oils and natural gas. Certain regions, such as the northeastern United States, are faced with significant clean fuel availability problems during the winter months. If circumstances occur which would reduce the availability of clean fuels, fuel switching may not be a viable solution to NO_x, SO_x and particulate emissions.

An alternative to fuel switching is fuel treatment. As discussed in Section 4, ash-bearing fuels and fuels with high levels of other contaminants can be treated to reduce the pollution potential. Treatment methods are available to reduce particulate, sulfur, and trace element contaminants. However, these processes generate liquid waste streams which are high in dissolved and suspended solids which must be disposed of in an acceptable manner. Situations may occur in certain regions where regulations governing liquid waste disposal may prohibit discharge of the waste to municipal waste treatment facilities. The added burden of fuel treatment and additional waste disposal systems may make this option economically unattractive.

5.3.2 Equipment Considerations

Certain regions of the United States, such as the South Coast Air Quality Management District (SCAQMD) have substantially more stringent control requirements than other regions. Though NO_x control technology is available to meet these control levels, there will be an increased burden on existing equipment. For example, a higher water/fuel ratio would be required for wet control of NO_x. This may result in increased water volume requirements, larger water treatment facilities, potential increases in equipment corrosion, and an increased fuel penalty. Existing water treatment facilities must be able to meet the new water volume requirements. Operation and maintenance requirements may be increased, and water and fuel usage will be increased. If the turbine is located in a region where water and fuel supplies are limited, or existing water treatment facilities are straining to handle the increased burden, costs may rise substantially.

Water availability alone could be a significant factor in determining NO_x control strategy. In regions with limited water supplies, such as arid or arctic regions, it may not be reasonable to require the use of water or steam injection. A second water related problem is the increased volume of treatment waste from the water purification system. If facilities are limited to handle this waste material, water or steam injection may not be viable control options.

Reductions in NO_x emissions are generally associated with slight reductions in combustion efficiency. This generally results in increases of CO and UHC emissions as discussed in Section 5.2.2. Certain regions could be adversely affected by increases in incremental emissions such as unburned vapor phase hydrocarbons because of their contribution to photochemical smog and other health related situations. Those areas with pollution problems of this type may limit the emissions of these other criteria pollutants and thus substantially limit the effectiveness of NO_x control devices.

It is thus quite important when considering NO_x control technology to examine not only the basic system requirements, but also the impact the control may have on other plant facilities and the surrounding environment.

5.4 SUMMARY OF PERFORMANCE AND COSTS OF NO_x CONTROLS

Performance and costs associated with wet and dry NO_x controls for stationary gas turbines are summarized in this section. Details of performance, cost and incremental impacts of specific control techniques have been discussed earlier. There are certain aspects of both wet and dry NO_x controls where there is a serious lack of data necessary to form even qualitative conclusions. Also, some aspects of this evaluation have relied on data which shows considerable variation among users, manufacturers and EPA. There does not seem to be much argument that wet controls are now fully capable of reducing NO_x emissions to the standard of 75 ppm at 15 percent O_2. Also, manufacturers expect dry NO_x controls (exclusive of catalytic combustion) to be fully developed and operational in large scale turbines within 5 years. Assigning costs to the various control options and evaluating their effect on operations and maintenance is where the most inconsistency in estimates occur.

5.4.1 Wet Controls

Industry has long accepted water and steam injection as a suitable method for NO_x control. Depending on the water/fuel ratio, emission reductions can be as great as 80 percent. Existing utility engines in the 60 MW range will be capable of reducing NO_x emissions approximately 45 percent using a 0.5 water/fuel ratio. This is sufficient reduction to lower NO_x emissions below the proposed standard of 75 ppm at 15 percent O_2. Recent studies have shown that wet controls can actually aggravate the NO_x problem when fuels containing bound nitrogen are used. Depending on the water/fuel ratio and operating conditions, emissions of unburned hydrocarbons and CO may increase. Water or steam may have a localized detrimental effect on combustion efficiency within the primary combustion zone, thereby inhibiting complete oxidation of hydrocarbons and CO.

There is considerable disagreement about the impact that wet controls have on the daily operations and maintenance of gas turbines. An increase in engine heat rate, manifested as a maximum of 5 percent increase in fuel usage, is the most significant impact on operations. This may be offset somewhat by increased power output caused by the increase in mass throughput. Periodic recharging of the water purification system will most certainly be required. Indeed, a full time operator/maintenance person may even be warranted for some installations. Some users have reported significant maintenance problems with the water treatment system itself and internal turbine problems due to water use. The nature of the latter type generally fall into one of the following two categories: hot parts embrittlement or particle deposition and contamination. It appears these items are not only affected by water quality, water/fuel ratio, and equipment types, but by day-to-day operations and maintenance procedures. At least two utilities have accumulated over 50,000 hours of wet NO_x control experience and have experienced no significant problems or outages directly attributable to the control technique.

A rather wide range of user-reported costs for water injection equipment on a per kilowatt basis has been found. A number of utilities have cited costs ranging from approximately \$5/kW to almost \$23/kW in 1978 dollars. EPA originally used a value of \$2.58/kW in 1975 dollars to estimate the economic impact of NO_x controls. They have subsequently revised their estimates to \$7/kW in 1978 dollars for a 60 MW gas turbine (Reference 5-24). The analysis here has used \$10/kW as a representative value for large scale turbines. It appears that actual capital costs will be very site specific and depend to a great extent on the required water purification equipment and to a lesser extent on turbine modifications. Additional operating and maintenance costs have been found to be approximately 3 percent of installed costs. The fuel penalty due to an increased heat rate with water injection is a significant portion of this additional expense.

The cost impact of wet NO_x controls on medium and small size gas turbines is more severe than for large engines which can show savings through economies of scale. Water injection for a 3 MW unit has been found to cost $30/kW, considerably higher than EPA's estimate reported in the SSEIS. Nonetheless, the total annualized cost to control using water injection should only increase the cost of electricity produced by 2 to 5 percent.

5.4.2 Dry Controls

Dry NO_x controls refer to unconventional combustors which are so designed that NO_x formation is reduced by combustion modification rather than by injection of water or steam. General concepts currently being developed by manufacturers to meet the NO_x NSPS involve modifications to the combustor design, fuel premixing and prevaporization, and improved airflow patterns. Catalytic combustion, although many years from full development in gas turbines, has shown dramatic reductions in all emissions approaching 98 percent in some cases. Catalytic technology has received only minor treatment in this report since manufacturers speculate that it has only a far term potential for gas turbines.

For detailed summaries of completed and some ongoing dry control research and development programs, see Section 5.2.1.3 and 5.2.1.4. The technical details of these programs will not be further summarized here. However, the NO_x and incremental emissions will be summarized. Lean burning in the primary zone and staged combustion in conjunction with some form of fuel/air premixing and prevaporization appears to be among the most promising dry control concepts for fuels containing minimal bound nitrogen. Researchers have obtained NO_x reductions approaching 80 percent in laboratory combustor rigs. Other techniques such as rich burning in the primary zone with quick quench in the secondary zone have shown dramatic NO_x reductions with both clean and dirty fuels. Most of these controls are being developed with the intent of minimizing emissions of CO and UHC as well as NO_x. Manufacturers have had varying degrees of success. While many designs face a NO_x/CO tradeoff, the EPA sponsored Pratt and Whitney rich-burn, quick-quench combustor appears to have isolated NO_x control from CO control. The problem becomes particularly difficult for lean combustors during off-design conditions when combustion is not very efficient. While formation of NO_x is somewhat inhibited under these conditions, incomplete oxidation of CO and UHC is favored. CO and NO_x emissions in lean combustors are very sensitive to changes in equivalence ratio. While a carefully implemented engine control system could control equivalence ratio, other problems, such as component deterioration, may tend to increase CO and UHC.

Since dry controls are essentially modified, although more complex, conventional combustors, there probably will not be any additional impact on operations and maintenance. Still, all of the problems manufacturers are experiencing in the developmental stage must be solved before these concepts are commercially employed on full scale engines. Moreover, new problems to be solved will undoubtedly surface during the scale-up process. Currently, it is not expected that dry controls will significantly affect heat rate. Combustor liners may have to be replaced more frequently than with conventional combustors. Other than periodic replacement of the catalyst cell, it is not known what additional maintenance procedures will be required with catalytic combustion technology.

At the present stage of development, it is very difficult to accurately estimate the economics associated with the implementation of dry controls. For utility size turbines, manufacturers speculate that dry controls will cost somewhat less than wet controls for a comparably sized unit. The size of the base over which developmental costs can be distributed seems to be a dominant factor in the actual cost. Maintenance costs should not be great since dry control combustor liners can be replaced on a periodic basis as are current combustor liners, although possibly more frequently. The cost impact on smaller turbines is expected to be more substantial since there is a smaller base to spread development costs over.

In summary, wet controls are the preferred, indeed the only NO_x control technique which are currently available to meet the recently promulgated NO_x performance standard for stationary gas turbines. Although the capital costs of water injection can be significant, approaching 20 percent of total unit cost on a per kW basis, total annualized control costs, including operating and maintenance, should increase the cost of power by only 2 to 5 percent.

Dry controls, as they become fully developed for full size engines, will begin to replace wet controls in new sources. They appear to be more attractive from virtually all standpoints, the most important of which is an emerging ability to control NO_x from high-nitrogen fuels such as residual oils and synthetic fuels. Catalytic combustion, while yielding extremely high pollutant reductions in subscale models, may only be feasible in the very long term.

5.5 PERFORMANCE AND COST FOR POLLUTANT CONTROLS OTHER THAN NO_x

This section must be prefaced by a statement regarding the relative importance of controlling the various pollutants produced by stationary gas turbines. NO_x is the primary pollutant of concern with gas turbines. Gas turbines also produce quantities of sulfur oxides, CO and UHC. But for various reasons control of these pollutants is either relatively easy, prohibitively expensive or obviated by certain operating conditions of gas turbines.

Sulfur dioxide emissions from gas turbines are strictly a function of the fuel sulfur content. Virtually all fuel sulfur is converted to SO_2 in the combustion process. The easiest way to control SO_2 emissions is to regulate the sulfur content of the fuel. Gas turbines have traditionally burned clean fuels low in sulfur so this method of control should not be a great hardship. However, if trends in fuel use move towards the use of heavier fuels with higher sulfur content, some form of fuel desulfurization may be required. Economics and availability of fuels will dictate when desulfurization becomes viable. Flue gas desulfurization is at present extremely costly for gas turbines due to the high volumes of gas that must be treated. Costs of flue gas desulfurization are estimated to be from two to three times the cost of the gas turbine itself, thus making it unattractive.

Typical operating characteristics of gas turbines and the importance of controlling NO_x emissions considerably diminishes the problem of CO and UHC emissions. Most stationary gas turbines operate at full load and thus under conditions of high combustion efficiency. This greatly reduces CO and UHC emissions. When load is decreased, combustion efficiency decreases and emissions of unburned species increases. Control of these emissions is accomplished (secondarily to NO_x) by combustion modifications that enhance fuel/air mixing, fuel atomization, and control of equivalence ratios, and increased residence times to promote better combustion of UHC in the primary zone and CO in the dilution zone.

In summary, costs of SO_2 control are reflected directly in the costs and sulfur content of the fuel. Performance and costs of CO and UHC control follow control of NO_x. That is to say, while it is desirable to limit CO and UHC emissions, gas turbine pollution control research and development efforts have as their primary goal, control of NO_x. CO and UHC control are of secondary importance, and with the development of new dry control combustors, manufacturers will control CO and UHC in order to maximize combustion efficiency.

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SECTION 6

ENVIRONMENTAL ASSESSMENT

Unlike most stationary sources which have potential multimedia pollution control problems, the impact of stationary gas turbines is almost exclusively on ambient air. Solid or liquid waste impacts are minimal. Although gas turbines represented only a 2 percent share of the total anthropogenic NO_x emissions for the year 1977, this does amount to 210,000 Mg (232,000 tons) (Reference 6-1). Due to the nature of most gas turbine installations (i.e., clustered in groups of multiple units) certain circumstances of operations, ambient background pollutant levels and meteorological conditions can cause ambient standards to be exceeded locally (Reference 6-2). Consequently the main focus of this section will be on assessing the environmental impact of pollutant controls for gas turbines on ambient air levels.

The environmental assessment discussion begins in Section 6.1 with a quantitative multimedia impact analysis of a typical gas turbine, comparing uncontrolled and controlled operation. Then the discussion focuses in Section 6.2 on the environmental impact of gas turbines on air, since the principle effluent is in the form of flue gas emissions. Planned and existing emissions standards on the Federal, state, and local levels are reviewed and compared with emission levels from uncontrolled and controlled firing. In addition, potentially hazardous, but as yet unregulated pollutants (including those with no proposed regulations), are discussed. These include sulfates and polycyclic organic matter (POM). The effect of NO_x controls on incremental emissions of other pollutants has been discussed at great length in Section 5.2.2. It was found that these incremental emissions can vary greatly depending on the type of control, the degree of care in which the control was implemented (particularly with dry controls), the fuel type, the load, and other operating conditions.

Although primary focus is on air emissions, gas turbines do cause additional environmental impacts. However, in comparison with the relative magnitude of the air impacts, other multimedia "wastes" are easily controlled and relatively innocuous. These include noise impacts, solid wastes such as water treatment system residue and liquid wastes such as waste water from the water treatment system. Evaluation of these impacts is presented in Section 6.3.

Evaluating the effect that emission controls have on gas turbine operation and maintenance is an integral part of assessing the performance of those controls. This is discussed in Section 6.4. NO_x controls can affect operating parameters as well as maintenance requirements. Although maintenance requirements are highly variable among different users, wet controls appear to have a greater impact than do dry controls. For example, some users and manufacturers report a 2 to 5 percent heat rate increase with wet controls, while dry controls are not expected to affect heat rate. Data for this evaluation have been collected primarily from users and are, for the most part, only qualitative in nature. The limitation is the lack of long term user experience.

In assessing the economic impact of NO_x controls, this assessment took into account such factors as the economic environment of the industry, incremental capital and operating costs of controls, and cost in terms of efficiency losses, increased fuel use requirements, fuel availability and net effects on operations and maintenance requirements and schedules. Section 6.5 reviews the cost analysis results presented in Section 5.2.3. Through a formalized costing procedure based on user supplied data, through figures reported in the literature and supplied by manufacturers and, in some case (for dry controls), through semi-quantitative estimates, a ranking of controls based on cost effectiveness is derived (Sections 6.5 and 6.6). The present stage of control technology development was also an important consideration.

6.1 ENVIRONMENTAL IMPACT ANALYSIS

If the environmental assessment of stationary gas turbines is to be compared on a consistent basis with other environmental assessments, standardized methodologies must be employed. Using Level 1 analyses from an Acurex test (sponsored by EPA under this NO_x EA program) on a 60 MW oil-fired utility gas turbine, potential problem pollutants and pollutant control priorities have been determined. Through the use of an IERL Source Analysis Model, specifically SAM IA, problem areas and priorities can be identified by establishing maximum discharge severities and weighted discharge severities (References 6-3 through 6-6).

The SAM IA model defines two indices of potential hazard. The first, termed Discharge Severity (DS), is the ratio of a pollutant species discharge concentration to that species' Discharge Multimedia Environmental Goal (DMEG). The DMEG values represent maximum concentrations acceptable in effluent streams and are defined to preclude adverse effects from acute exposure. The DMEG's are generally defined to be pollutant levels safe for occupational exposure.

The second SAM IA hazard index, termed Weighted Discharge Severity (WDS), is defined to be the product of the DS with the effluent stream mass flowrate.

A summary of the data from the 60 MW oil-fired utility gas turbine tested is presented in Table 6-1. The concentration in the flue gas of the species from each MEG category analyzed for the baseline and water injection case, are presented. Table 6-2 presents the compounds for which the DS exceeded unity for either of the two tests. The emissions of CO_2, NO_2, SO_2, and H_2SO_4 exceeded the DMEG values while those of As, Cr, and Cl may have also. However, for these compounds there is a net potential environmental benefit (i.e. decrease in emissions) when using water injection. The organic compounds terphenyl, naphthalene, pyrene, and fluoranthrene were found during the water injection test but not during the baseline test. However, their DS values were less than 1.

6.2 ENVIRONMENTAL IMPACTS ON AIR

This section analyzes the ambient air impact of emissions from gas turbines, with the primary emphasis on NO_x. The discussion begins with a review of existing or planned NO_x control standards and then compares waste stream emissions, both controlled and uncontrolled, with these standards.

6.2.1 Summary of NO_x Control Regulations

The Federal Standards of Performance for New Stationary Sources (NSPS) provide the limitations for emission of NO_x pollutants from stationary sources on a national basis. The NSPS are intended largely to

TABLE 6-1. EMISSIONS FROM A 60MW UTILITY OIL-FIRED GAS TURBINE

MEG Category	Compound Assumed	Concentration ($\mu g/m^3$)	
		Baseline	Water Injection
01A	Methane	1.6×10^3	2.4×10^3
05C	t-Pentanol	620	520
08A	Maleic acid	620	520
08D	Phthalate ester	2.0	2.0
15A	Biphenyl	60	60
15B	Terphenyl	--	5.0
18A	Phenol	1.0	1.0
21A	Phenanthrene	0.5	1.0
21A	Naphthalene	--	1.0
21B	Pyrene	--	0.5
22A	Fluoranthrene	--	0.5
32	Be	<0.92	<0.14
36	Ba	<3.5	<3.6
37	B	$<2.2 \times 10^2$	$<2.0 \times 10^3$
41	Tl	<11	<10
42	CO	7.0×10^3	1.0×10^4
	CO_2	8.0×10^7	8.4×10^7
45	Sn	<16	<44.1
46	Pb	82	23
47	NO_2	3.5×10^5	1.5×10^5
49	As	<14	<14
50	Sb	<4.6	<4.7
51	Bl	<1.8	<2.3
53	SO_2	3.1×10^4	3.4×10^4
	H_2SO_4	8.1×10^3	6.0×10^3
54	Se	<11	<10
55	Te	<3.6	<3.4
62	Ti	<29	<33
65	V	<22	<49
68	Cr	<17	<7.5
69	Mo	<5.8	<4.8
71	Mn	<0.48	<0.05
72	Fe	71	89
74	Cc	<0.55	<0.13
76	Ni	<0.24	<0.61
78	Cu	42	60
81	Zn	<760	800
82	Cd	<13	<0.55
83	Hg	<2.8	<21

Total Flue Gas Flowrate:

Baseline	250 kg/s
Water injection	242 kg/s

TABLE 6-2. EMISSIONS WITH CONCENTRATIONS GREATER THAN DMEG VALUES

MEG Category	Compound Assumed	Discharge Severity (DS) Baseline	Discharge Severity (DS) Water Injection
42	CO_2	8.89	9.33
47	NO_2	38.9	16.7
49	As	<7	<7
53	SO_2	2.38	2.62
	H_2SO_4	8.1	6
68	Cr	<17	<7.5
82	Cl	<1.3	<0.055

assist in air quality maintenance by offsetting increases due to source growth through the application of control technology. The development and demonstration of NO_x control technology allows EPA to prepare for the setting of future NSPS based on the best system for emission reductions. The NSPS NO_x limit for stationary gas turbines with heat input more than 2.2 MW (7.5 MBtu/hr) is 75 ppm at 15 percent O_2. Specific corrections are allowed for efficiency and fuel nitrogen.

The primary responsibility for air quality attainment and maintenance, however, rests with the individual states and the emission standards established under the State Implementation Plans (SIP), not at the Federal level. The state and local standards for new and existing stationary fuel combustion equipment, including gas turbines, are presented in Table 6-3. As in the case for the NSPS, the basis for these standards is by application of combustion process modification as demonstrated through retrofit technology. With the exception of the South Coast Air Quality Management District (SCAQMD), the standards are largely directed at future air quality maintenance rather than attainment. Some areas have exercised the option to set more stringent standards than required for maintenance by the SIP. The SCAQMD has a serious attainment problem and has accordingly instituted the most comprehensive and stringent emission regulations. In fact, the control development in the SCAQMD has been so intense that it is useful as a guide to the limits of current technology for existing gas- and oil-fired equipment. The trend in the SCAQMD and elsewhere has been toward regulating smaller equipment

TABLE 6-3. SUMMARY OF STATE AND LOCAL NO_x EMISSIONS STANDARDS FOR STATIONARY SOURCES[e] (Reference 6-1)

	Equipment[d]			Standard[b,e]			Effective Date	Comments[d]
	New or Existing	Type	Heat Input Capacity[a]	Gas Fired	Oil Fired	Coal Fired		
CALIFORNIA[f]								
Bay Area QM	New	Heat transfer	73 (250)	125 ppm	225 ppm	--		
	All	Heat transfer	513 (1750)	175 ppm	300 ppm	--	4/19/75	
Monterey Bay	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
	All	Fuel burning	440 (1,500)	125 ppm	225 ppm/hr	--		
	All	Fuel burning	440 (1,500)	225 ppm	225 ppm	--	9/16/76	
San Diego	All	Fuel burning	15 (50)	125 ppm	225 ppm	225 ppm		
San Joaquin	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
	New	Fuel burning	520 (1,775)	125 ppm	225 ppm	225 ppm	1/1/75	
Kern Co.	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
Santa Barbara APCD	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
	All	Fuel burning	520 (1,775)	125 ppm	225 ppm	--	1/1/75	
Counties in SCAQMD:								
LA Co.[c]	All	Equipment	520 (1,775)	225 ppm	325 ppm	--	12/31/71	
	All	Equipment	520 (1,775)	125 ppm	225 ppm	--	12/31/74	
	New	Equipment	73 (250)	125 ppm	225 ppm	--		
Orange Co.[c]	Existing	Equipment	147-630 500-2,150)	225 ppm	325 ppm	--	12/31/72	
	Existing	Equipment	630 (2,150)	225 ppm	325 ppm	--	12/31/72	
	Existing	Equipment		125 ppm	225 ppm	--	12/31/75	

TABLE 6-3. Continued

	Equipment^d			Standard^{b,e}			Effective Date	Comments^d
	New or Existing	Type	Heat Input Capacity^a	Gas Fired	Oil Fired	Coal Fired		
San Bernardino Co.^{c}	Existing	Equipment	520 (1,775)	125 ppm	225 ppm	--	1/1/75	
Riverside Co.^{c}	Existing	Equipment	205 (700)	225 ppm	325 ppm		12/31/71	Applies to West Central Area Only
	Existing	Equipment	205 (700)	125 ppm	225 ppm		12/31/74	Applies to West Central Area Only
	Existing	Equipment	520 (1,775)	125 ppm	225 ppm		1/1/75	Applies to Balance of County
	New	Equipment		64 kg/hr^g	64 kg/hr^g	64 kg/hr^g		
SCAQMD	All	Fuel burning	523-628 (1,786-2,143)	125 ppm	225 ppm	325 ppm		
	All	Fuel burning	628 (2,143)	125 ppm	225 ppm	225 ppm		
	All	Fuel burning	161-523 (550-1,786)	300 ppm	400 ppm	400 ppm	1/1/77	
Ventura Co. APCD	New	Fuel burning		64 kg/hr^g	64 kg/hr^g	64 kg/hr^g		
	New	Fuel burning	73 (250)	125 ppm	225 ppm	--		
	All	Fuel burning	73-630 (250-2,150)	250 ppm	250 ppm	250 ppm		Except peaking units at Mandalay
	All	Fuel burning	630 (2,150)	125 ppm	225 ppm	--		
CONNECTICUT	Existing	Fuel burning	73 (250)	86.1 (0.2)	129 (0.3)	387.3 (0.9)		Except GT, IC
	New	Fuel burning	1.5-73 (5-250)	86.1 (0.2)	129 (0.3)	301 (0.7)		Except GT, IC
	Existing	Fuel burning	1.5-73 (5-250)	86.1 (0.2)	129 (0.3)	387.3 (0.9)		Except GT, IC; variances permitted
	All	GT		387.3 (0.9)	387.3 (0.9)	387.3 (0.9)		

TABLE 6-3. Continued

	Equipment[d]			Standard[b,e]			Effective Date	Comments[d]
	New or Existing	Type[c]	Heat Input Capacity[a]	Gas Fired	Oil Fired	Coal Fired		
ILLINOIS								
Lake, Will, Du Page, McHenry, Kara, Grundy, Kendall, Kankakee, Macon, St. Clair, Madison Cos.	Existing	Fuel combustion	73 (250)	129 (0.3)	129 (0.3)	387.3 (0.9)		Except cyclone & horizontally opposed fired boilers burning solid fuel
Cook Co.	New	Fuel combustion	59 (200)	86.1 (0.2)	129 (0.3)	301 (0.7)		
	Existing	Fuel combustion	59 (200)	129 (0.3)	129 (0.3)	387.3 (0.9)		
INDIANA	Existing	Fuel burning	73 (250)	86.1 (0.2)	129 (0.3)	301 (0.7)		Applies to "Priority Basin A" only -- none at present
MARYLAND	New	Fuel burning	73 (250)	86.1 (0.2)	129 (0.3)	215.2 (0.5)		Applies to "Priority I" AQCR's only
NEW MEXICO	New	Gas burning	1,055,000 GJ/yr (1,000,000 MBtu/yr)	86.1 (0.2)		301 (0.7)	12/31/74	
	Existing	Gas burning	1,055,000 GJ/yr (1,000,000 MBtu/yr)	129 (0.3)			12/31/74	
	All	Oil burning	1,055,000 GJ/yr (1,000,000 MBtu/yr)		129 (0.3)			
NEW YORK	All	GT, IC	73 (250)	86.1 (0.2)	129 (0.3)			

TABLE 6-3. Concluded

	Equipment[d]			Standard[b,e]			Effective Date	Comments[d]
	New or Existing	Type	Heat Input Capacity[a]	Gas Fired	Oil Fired	Coal Fired		
OKLAHOMA	New	Fuel burning	15 (50)	86.1 (0.2)	129 (0.3)	301 (0.7)		
SOUTH DAKOTA	All	Fuel burning		86.1 (0.2)	129 (0.3)			
VERMONT	New	Combustion	73 (250)	--	129 (0.3)	--	7/1/71	Except GT
	New	GT	73 (250)	--	129 (0.3)	--	7/1/71	
WYOMING	New	Gas burning		86.1 (0.2)	--			Except IC 59 (200)
	Existing	Gas burning		99 (0.23)				
	New	Oil burning	0.29 (1)	--	129 (0.3)	--		Except IC 59 (200)
	New	Oil burning	0.29 (1)	--	258.2 (0.6)	--		Except IC 59 (200)
	Existing	Oil burning	73 (250)	--	197.9 (0.45)	--		Except IC 59 200)
	Existing	Oil burning	73 (250)	--	258.2 (0.6)	--		Except IC 59 (200)

[a] Unless stated otherwise, units are MW (10^6 Btu/hr)
[b] Unless stated otherwise, units are ng/J (lb/10^6 Btu)
[c] Rules put into effect before SCAQMD was formed and replaced by SCAQMD rules
[d] GT refers to gas turbines; IC refers to reciprocating internal combustion engines
[e] NO_x emission standards in chronological order in so far as possible, standards which are similar to federal standards have been omitted
[f] All ppm standards are at 3 percent O_2
[g] 140 lbs/hr

categories and tightening the regulations on larger equipment. The SCAQMD regulations are currently being evaluated as part of the SIP revision to determine if further emission reductions are practical.

Maintenance of air quality in the 1980's and 1990's will require NO_x regulations in addition to those existing or planned. New source controls will be emphasized since experience has shown them to be more effective, less costly and less disruptive than retrofit control of existing equipment.

6.2.2 Comparison of Emissions to Standards

The NO_x reduction capability of wet NO_x control techniques was presented in Figure 5-2. Table 6-4 compares the potential levels of NO_x reduction with wet controls to the Federal standard of 75 ppm at 15 percent O_2 and to the more stringent regional standards.

In principle (although not always in practice), water or steam injection is fully capable of controlling NO_x emissions to proposed and existing standards; it is simply a matter of the correct water/fuel ratio. For example, a distillate oil-fired simple cycle gas turbine with baseline (uncontrolled) NO_x emissions of 170 ppm (all emissions at

TABLE 6-4. DEGREE OF WET CONTROL REQUIRED TO MEET REGIONAL NO_x STANDARDS

Fuel	Baseline Emissions -- ppm @ 15% O_2	Existing NO_x Standard -- ppm @ 15% O_2 and Equipment Category[a]	Required Water/Fuel Ratio to Meet Standard
Oil	170 ppm	75 ppm for new and existing sources	0.5
Gas	110 ppm	42 ppm for new and existing sources	0.6

[a] Regulations from counties in the Southern California Air Pollution Control District.

15 percent O_2) can meet the NSPS of 75 ppm with a 0.5 water to fuel ratio. The same turbine firing gas would emit 110 ppm uncontrolled. In this case, a water/fuel ratio of 0.6 would be sufficient to meet the Southern California standard of 42 ppm.

Dry NO_x controls are being developed as a replacement for wet controls, which many users claim are costly, complicated, and difficult to maintain. Of course, they are being designed to meet the NSPS and for some fuels, such as natural gas, are even expected to meet the most stringent regional regulations. As an example, Pratt and Whitney's Low NO_x Combustor Program has met their program goal of 75 ppm NO_x. In fact, even with the firing of fuel containing 0.5 percent nitrogen, NO_x emissions were as low as 50 ppm (Reference 6-7).

It appears then that while wet controls are fully capable of meeting all NO_x regulations by varying the water/fuel ratio, dry controls will probably evolve into the preferred technique once they are commercially demonstrated to meet existing and proposed emission regulations.

6.2.3 Ambient Air Impact

The ambient air impacts of SO_2, CO and NO_x emissions from gas turbines have been analyzed by EPA (Reference 6-2) using the basic Gaussian plume model with estimations and assumptions appropriate to the special plume characteristics of stationary gas turbines. The modeling studies have accounted for variations in fuels, degree of control, equipment configurations (i.e., individual versus cluster arrangements), and meteorological conditions. The concentration and ambient air impact of emissions can be estimated over distinct averaging times through the use of these dispersion models. The estimates can then be compared to the National Ambient Air Quality Standards (NAAQS).

The environmental impact of nine gas turbine units was analyzed for individual and clustered arrangements (Reference 6-2). CO emission estimates exceeded the NAAQS in only one instance, with eight clustered units operating in the spinning reserve mode. This mode of operating represents idle (no load) conditions where CO emissions can approach 100 times the emission rate at design (full) load (Reference 6-2).

The potential for SO_2 emission rates to exceed the short term NAAQS occurred often. However, the SO_2 average was found not to exceed air quality standards on an annual basis. Obviously if point sources are controlled to meet short term standards, the annual standard would never be exceeded.

Annual average NO_x concentration estimates for individual gas turbines did not exceed the NAAQS. However, the short term average for multiple (16-clustered) turbine units was found to be approximately five times the impact of an individual unit. If the same factor is applied to annual average estimates, uncontrolled units could potentially exceed the NAAQS for NO_2.

Gas turbine units are generally characterized by short, rectangular stacks. Results reported in Reference 6-2 show that higher concentrations can occur in regions with stronger, steadier winds. Since the effluent stacks from gas turbines typically reach the heights of nearby buildings, the wind turbulence in the vicinity of the buildings can cause high ground level concentrations. As might be expected, it was found that taller stacks will result in reduced ambient concentrations.

Additional studies have been conducted which predict ambient air impacts of NO_x controlled gas turbines through the use of dispersion models (Reference 6-8). These studies have also included individual and cluster arrangements as well as other variables. The results consistently show that the annual ground level NO_x concentrations from the given gas turbine units are in most cases, three orders of magnitude less than the NAAQS for NO_2 of 100 g/m^3 -- with the incremental contribution to uncontrolled ambient concentrations ranging from 0.07 to 1.2 g/m^3. Although small, this increase can have a significant impact on baseline ground level concentrations for nonattainment regions, where ambient NO_2 concentrations already exceed the NAAQS.

6.2.4 Bioassay Results

The organic extracts from the XAD-2 resin portion of the SASS train test on the 50 MW oil-fired gas turbine tested as part of this NO_x EA program (Reference 6-9) was subjected to bioassays. The Ames Salmonella Microsome plate test did not show any mutagenicity. While the WI-38 human cell cytotoxicity assay only showed low toxicity. These tests were performed on samples collected during the water injection test. Thus, it appears that the exhaust from this gas turbine operating under water injection has only low toxicity.

6.3 ADDITIONAL IMPACTS

A stationary gas turbine can represent a significant point source of noise pollution. However, muffler systems are available that reduce noise levels to 85 db, a safe level. The application of wet or dry NO_x controls is not expected to significantly alter these noise levels.

There are no radiation impacts associated with stationary gas turbines.

6.4 ASSESSMENT OF IMPACTS OF NO_x CONTROLS ON OPERATIONS AND MAINTENANCE

A pollutant control technique is not considered acceptable if it causes excessive technical problems and is economically unfavorable. Therefore as part of the assessment of NO_x control techniques for gas turbines, this section appraises the potential operations and maintenance effects as well as those reported by users who are already employing some form of NO_x control. This evaluation, in conjunction with the analysis of control technique performance, effect on incremental emissions, and cost (Sections 5.2.1, 5.2.2, and 5.2.3 respectively), will provide a realistic and comprehensive evaluation of gas turbine NO_x control techniques.

Initially it was hoped that sufficient data would be available to compare process variables under baseline or normal operating conditions to those under controlled or low NO_x modes. However, unlike some stationary sources such as utility boilers where there are a large number of parameters which must be continuously monitored, stationary gas turbines do not have this requirement. Indeed, many can and do run unattended for long periods. Furthermore, there is a large variation as to which operating parameters are measured between users. Another added hinderance is that some important variables, turbine inlet temperature for example, are proprietary with most manufacturers. While there are numerous large gas turbines currently with water injection capabilities, most are not in use since few regions of the country currently regulate NO_x emissions. The equipment is usually purchased as a hedge against future regulations. In light of this, much of the information for the analysis in this section has been taken from user experience in the case of wet controls and from experimental test results in the case of dry controls.

Significant operational and maintenance problems have been experienced by many users, and these are discussed in detail. Some companies have accumulated long hours of operation (in excess of 90,000 hours) using water injection and obtained favorable maintenance records. Since for all intents and purposes dry NO_x controls have not been implemented, actual long term user experience and data do not exist. Potential problems with dry controls noted here are based on research and development experience. Of course most, if not all, of these problems must be solved before dry controls become commercially viable. The following discussion points out the types of operational and maintenance problems inherent with new and complex combustor technology.

6.4.1 Wet Controls for NO_x Reduction

Wet controls for NO_x reduction in gas turbines refer to injecting steam or more commonly, water, directly into the combustion chamber. Since some of the thermal energy is used to heat the water, the peak flame temperature decreases, resulting in lower NO_x emissions. One negative aspect of having to heat additional material in the combustor is decreased overall system efficiency manifested as increased fuel consumption. Reported values have ranged from zero to five percent increase in heat rate with two percent as the average. The economic effect on overall gas turbine ownership due to increased heat rate is discussed in Section 5.2.3. Almost all the other reported operational and maintenance impacts due to water injection can be classified as particle deposition and contamination problems or difficulties related to the water treatment system. There are some positive consequences of using water injection, aside from substantially reducing NO_x. While thermal efficiency can decrease, maximum power output is simultaneously increased from two to three percent depending on the water/fuel weight ratio. In fact, water injection has been used for load augmentation in gas turbines since the early 1960's (Reference 6-2). One major manufacturer commented that water injection may also help to cool combustor walls, thereby prolonging service life. This is speculation, however, and is not supported or refuted by actual user data.

Gas turbine manufacturers typically specify a total contaminant level allowed in the combustor, based on impurities in combustion air, fuel and water. The degree of water purification then depends on contaminants in the other fluids in addition to the make-up water quality. Some users have reported that water injection has decreased component life by as much as 15 percent (Reference 6-10), although they are not certain whether the increased maintenance is due to the water injection or to the increasing age of the units. These same units, General Electric Frame 5's burning natural gas and distillate oil, have experienced embrittlement of hot combustion parts with water but not with steam injection. The Public Service Department of the City of Glendale, California has considerable experience with wet NO_x controls. One unit, a 31 MW simple cycle machine, has been in use since 1973 with a five percent capacity factor. Thus far, no additional operational and maintenance problems have been noted due to the water injection system. A second unit is a combined cycle plant utilizing waste heat recovery boilers to repower two old 20 MW steam turbines. The unit generates a total of 120 MW, 30 MW of which is due to boilers, and is used for base load power. Steam injection is used for NO_x control. A requirement for more frequent cleaning of fuel nozzles is the only additional maintenance item directly attributed to steam injection. One manufacturer has reported coking in fuel nozzles with the use of water injection in a particular installation (Reference 6-11).

It appears that a considerable number of turbine installations have had particle deposition and other problems related to contamination due to wet NO_x controls. There are many users, however, that report no increased maintenance problems associated with water or steam injection. A Southwest utility reports 2 year's, use of water injection on a Westinghouse 66 MW turbine and no problems with the water injection system or turbine problems caused by the wet NO_x controls. In fact, no significant deposits have yet been found on the turbine components (Reference 6-12).

One utility used water injection (for NO_x emission control) on two combined cycle plants for a total of 54,180 hours, without making any major changes to normal maintenance and operating procedures. They followed procedures essentially identical to those required for a similar machine not using water injection and the plant experienced no outages attributable to the water injection system during these operating periods. Another company accumulated approximately 92,000 hours of operating time with water injection on 17 turbines (1972 to 1978) with only about 116 hours of outage due to their water injection system. Maintenance records seem to indicate that, if run properly, water injection does not substantially increase maintenance requirements. The experience of Westinghouse in Japan seems to support this. They have four 501AA machines which use water injection continuously for NO_x control and Westinghouse indicates that they have received no negative reports regarding the effect of water injection on operations and maintenance (Reference 6-13).

Of the users contacted, approximately half were experiencing some sort of problem with the water purification system. It appears that most, if not all, of these problems can be obviated by good preliminary design of the treatment system, and through careful installation and maintenance procedures. In other words, water treatment systems employ conventional water purification technology and there is nothing inherent in them that would cause excessive problems which could not be avoided by the appropriate design and operation.

6.4.2 Dry Controls for NO_x Reduction

Dry controls for NO_x emissions are classified as those not involving water or steam injection but some form of combustor modification that favors conditions for limiting NO_x production. As previously mentioned, dry NO_x controls have not generally been developed and implemented to the degree where they can reduce NO_x emissions to 75 ppm at 15 percent O_2. Most manufacturers agree that at least 3 to 5 years is required before dry controls will be able to meet this emission goal and become commercially viable. Thus, essentially no user experience on the operational and maintenance effects of using dry controls is available. This section simply points out the types of problems that researchers have been experiencing during the dry control R&D programs. Again, it must be kept in mind that most of these problems will be solved before dry controls are implemented. This section discusses the generic types of problems that future users potentially may experience if dry controls are not adequately developed or if they are not properly operated and maintained.

It appears that most problems with dry control techniques are contained in five general categories:

- Combustor exit gas temperature profile
- Combustor structural integrity
- Premixed combustor flashback and autoignition
- Combustor airflow distribution and control
- Carbon deposits.

Pratt and Whitney and Solar have done experimental combustor rig work with premixed combustors (References 6-14 and 6-15). Both programs were discussed in detail in Section 5.2.1.3. The Pratt and Whitney premixed combustor for aircraft turbines experienced substantial problems in virtually all of the above categories . Combustor exit gas temperatures were found to be excessively high and characterized by a distorted radial temperature profile. Certain combustor configurations suffered burning, buckling and cracking as well as carbon deposits. Solar's lean reaction premix type combustor experienced flashback within the premix chambers under certain loads. This made it difficult to obtain consistent levels of NO_x emissions.

United Aircraft studied a prevaporized premixed combustor concept which employed an external heat exchanger to vaporize the fuel prior to injection into the combustor. Significant problems were encountered with coking and pyrolysis product deposition on heat exchanger tubes. It is imperative that tubes be kept clean for long periods to maximize the heat exchanger effectiveness which ultimately affects NO_x emissions.

Another Pratt and Whitney program studied the concepts of vortex mixing and burning and prevaporization-premixing. This program suffered most of the generic problems mentioned earlier including:

- Airflow distribution problems causing high pressure losses
- Poor combustor exit temperature profiles
- Coking in heat exchangers
- Combustor durability
- Carbon deposits on combustor liners and in fuel injectors.

The researchers report that most of these problems can be eliminated through proper design aimed at improving airflows and distribution.

In summary, it appears that most difficulties related to dry NO_x controls, while a number of years away from being solved, will be resolved before this control technology becomes accepted. However, these combustors, in some cases, especially those requiring variable geometry, appear to be more complicated, with an increased number of parts and more complex geometry than today's conventional combustors. This may complicate operations and increase the chance of failure. Combustor liners may have to be replaced more often (Reference 6-16). On the positive side, it appears that thermal efficiency will not be affected by conversion to dry controls (Reference 6-16).

6.5 ECONOMIC IMPACT OF NO_x CONTROLS

Wet controls will increase the price of gas turbines and increase the fuel usage per kilowatt generated. Dry controls may increase gas turbine prices but are not expected to increase fuel usage. Dry controls are not presently available but should be by 1983. For utility size turbines, wet controls are now being used but they are not being used on the smaller size turbines. All of the above were discussed in Section 5.2.3 along with estimated costs for typical turbines. This section covers the total impact on the industry and consumer. The economic impact will only be discussed through 1983 and mainly wet controls will be discussed. Wet controls will have the largest effect since dry controls, for all intents and purposes, will not be available in the near term.

Table 6-5 summarizes projected installed costs and annualized cost for various control techniques and NO_x emission levels. The two main points that these data indicate are: (1) that all costs increase as the degree of control is increased and (2) dry control costs are expected to be less than costs of wet controls. Considerd a far term technology, costs of catalytic combustion are very difficult to estimate.

6.5.1 Impact on Manufacturers

The impact on the manufacturer comes from how these controls will affect his sales. Can he pass the increased costs to the consumer and still remain competitive? Also, will the NO_x controls change the operating characteristics so that other types of power generators will be bought instead? Will one manufacturer have an advantage over another?

TABLE 6-5. PROJECTED CONTROL REQUIREMENTS FOR ALTERNATE NO_x EMISSION LEVELS

NO_x Emission Level, ppm @ 15 % O_2	Control Technique	Install Cost $/kW	Annualized Cost mills/kWh
130	Water Injection	8	3.5
75	Water Injection	10	4.0
40	Water Injection	12	4.7
75	Dry controls (1983)	NA	NA
5	Catalytic combustion (1985-1990)	NA	NA

Notes:

Peaking utility turbine, baseline NO_x -- 175 ppm @ 15% O_2
Based on Table 5-11 assumptions and data
Fuel penalty and capacity enhancement assumed linear with water/fuel ratio
Dry control costs expected to be somewhat less than wet controls

For utility turbines, all manufacturers will be adding the same type of wet controls so no one should have an advantage over another. For dry controls, if one manufacturer were to develop a dry control that was easier to use and much lower in capital cost, he might have an advantage, but as of now, this has not happened. For peaking units, gas turbines have a large advantage over boilers because of their quick startup time. NO_x controls should not change this. For wet controls, an isolated unit might require a little more attention because of the water purification system but at least one user did not find this to be a problem (Reference 6-17). For base load operation, new turbines are becoming more efficient and because of their lower capital cost, they may eventually become competitive with boilers (Reference 6-18). Wet controls do increase costs and lower efficiency but this should not change the advantages turbines have as peaking units. Since dry controls are not expected to lower the efficiency nor are they expected to raise the cost by a significant amount, they too should not diminish the advantages of gas turbines as peaking units.

For the smaller size gas turbines, there is stiff competition from diesel engines. Gas turbines are cheaper to manufacture but use more fuel. Wet controls will increase the price of turbines and lower their fuel efficiency, therefore if diesel engines are unregulated, gas turbines will lose ground. However, in all probability there will also be regulations promulgated for diesel engines. Also, even with wet or dry NO_x controls, gas turbines will remain cheaper to produce than diesels. Dry controls will have less impact than wet controls because they should not increase the fuel usage. Also with dry controls, the turbines should be easier to operate, which would lessen the impact on isolated operation and minimize operating costs.

6.5.2 Impact on Consumer

The largest consumer, in terms of capacity, of stationary gas turbines is the electric utility industry. Wet NO_x controls will increase their cost of producing electricity through higher capital and operating costs. In predicting the effect of wet controls, it was assumed that only new installations will be affected and all new installations will be using wet controls. Once dry controls become proven and available, wet controls will be used less often. As a means of estimating the number of new gas turbine installations, we have used estimates provided by the National Electrical Manufacturers Association (Reference 6-19). Since smaller size turbines (less than 2.2 MW heat input) will probably not require NO_x controls for 5 years, they are not considered in this analysis.

Table 6-6 summarizes the predicted NO_x economic impact of wet NO_x controls to meet proposed NSPS for utility gas turbines from 1978 to 1983. To obtain a reduction of 175 ppm NO_x at 15 percent O_2 to 75 ppm, that would be a reduction of 45.8 x 10^6 kg of NO_x in 1983 at a cost of 0.8 mills/g NO_x for gas turbines added since 1977. The electricity produced from these turbines would cost two to three percent more because of these wet controls. Since less than 2 percent of the net power generation of utilities is by gas turbines, these increased costs are minor (Reference 6-2).

TABLE 6-6. PREDICTED ECONOMIC IMPACT OF WET NO_x CONTROLS TO MEET PROPOSED NSPS FOR UTILITY GAS TURBINES: 1978-1983[a]

Type cycle	Additions (MW)	Cost of wet controls (10^3 \$)	1983 increased fuel use due to NO_x control (10^6 GJ)	1983 increased fuel cost due to NO_x control (10^3 \$)	Annualized control cost (10^3 \$)	$\frac{\text{mills}}{\text{g } NO_x}$
Simple	4927	49,270	0.5	2,000	14,300	3.25
Combined	3253	32,530	4.9	19,600	27,700	0.7
Total	8180	81,800	5.4	21,600	42,000	0.9

Assumptions

Fuel cost (\$/GJ)	\$4.00
Heat rate (GJ/kWh)	
Simple	0.0109
Combined	0.0095
Cost for wet controls (\$/kW)	10.00
NO_x reduction (ng/J) required to meet NSPS of 75 ppm @ 15% O_2	167
Fuel penalty (%)	2
Hours/year used	
Simple cycle	500
Combine cycle	8000

Annualized cost = 25% of installation cost + increased fuel cost, where 25% = 20% for fixed costs + 5% operation and maintenance

[a] Since regenerative cycle machines constitute a low percentage of the installed turbines and the regenerative market has been very slow, they were not considered in this analysis.

6.6 EFFECTIVENESS OF NO_x CONTROLS

Table 6-5 summarizes the percent of NO_x reduction achievable with the Best Available Control Technology (BACT) for stationary gas turbines, i.e., water injection. The amount of NO_x reduction can be varied by changing the water/fuel ratio. However, certain tradeoffs, such as greater expense and increased maintenance and operation problems, tend to limit the percent reduction achievable. Also shown in Table 6-7 are control potentials for advanced technologies. While dry controls (employing various combustion modification techniques) are expected to be commercially available by 1983, catalytic combustion's future is less certain, although the NO_x control payoffs are potentially much greater.

Wet controls are a proven NO_x control technology. Section 5.2.1.1 has shown that water and steam injection are capable of reducing NO_x emissions on clean fuels to below the NSPS emission limit of 75 ppm at 15 percent O_2. The degree of NO_x reduction achieved can be controlled by adjustment of the water/fuel ratio. Increasing this value increases the percent of NO_x reduction. Typically a water/fuel ratio of 0.5 would be sufficient to reduce uncontrolled NO_x emissions in a 60 MW oil-fired simple cycle gas turbine to a value below 75 ppm. To obtain this same level of NO_x reduction when firing natural gas, a ratio of only 0.25 would be required since the uncontrolled NO_x emission level when firing gas is less than when firing oil. Wet controls are not likely to be applied to engines firing dirty fuels since studies have shown them to be counter-productive to NO_x reduction in the presence of fuel bound nitrogen.

The costs associated with the degree of control through the application of wet controls are difficult to accurately quantify. Utility users have reported installed costs of water injection ranging from \$5 to \$23/kW in 1978 dollars. In addition to capital costs, there are annual operating and maintenance costs, including water treatment costs and a fuel penalth due to a two to five percent increase in heat rate. These cost effects are even more severe for small size turbines where economies of scale cannot be realized.

Dry NO_x controls are currently being developed with the intent of fully replacing wet controls in new stationary turbines by the early 1980's. Indeed, users would welcome the day when they could replace wet

TABLE 6-7. NO_x CONTROLS: BEST AVAILABLE CONTROL TECHNOLOGY (BACT) AND ADVANCED TECHNOLOGY

	Control Technique	NO_x Emission Level,[a] ppm at 15% O_2
BACT	Water Injection	
	.25 water/fuel ratio	130
	.50 water/fuel ratio	75
	.75 water/fuel ratio	40
Advanced Technology	Dry Controls (1983)	40
	Catalytic Combustion (1985-1990)	10

[a] For clean liquid and gaseous fuel, typical peaking utility gas turbine, values are ± 20 percent, baseline NO_x emission - 175 ppm at 15% O_2

controls with the more simplified and less costly dry controls. One of the most promising designs comes from an EPA program being conducted by Pratt and Whitney Aircraft. The experimental portion of this program has been completed with the most promising dry control concept, rich burn/quick quench, having been tested in a scale-up to the 25 MW size range. All program goals were met and exceeded. NO_x levels were approximately 40 ppm with clean fuels and as low as 75 ppm with 0.5 percent fuel nitrogen. CO emissions were well below 100 ppm, indicating excellent combustion efficiency. In addition, the dry control combustor, when commercially available, is expected to cost only 15 percent more than a conventional combustor. This is just a fraction of what wet controls would cost. Wet controls, both water and steam injection, have been shown in numerous installations to be fully capable of meeting NSPS. However, this does not come at negligible expense and headache to the user. These control systems can be costly to install and operate and some users have reported deleterious effects on the day to day operations and maintenance of their engines. Considerable operating and maintenance problems and costs associated with wet controls will be all but eliminated with dry controls. However, existing operational complexities will have to be solved before dry controls become commercially demonstrated.

NO_x emissions are probably the primary pollutant of concern with stationary gas turbines. CO and HC emissions are somewhat smaller in magnitude and not easily controlled without severely upsetting NO_x emissions. SO_x emissions are purely a function of the fuel sulfur content and can only be economically controlled by selecting low sulfur fuels. Flue gas desulfurization is, at present, prohibitively expensive for gas turbines. Since by most estimates the earliest that dry NO_x controls will be fully developed and demonstrated in full scale gas turbines is by 1982 or 1983, wet controls are certainly the preferred, indeed the only, means of controlling NO_x emissions in gas turbines.

Dry NO_x controls, when they become commercially available, will undoubtedly start to replace wet controls as the preferred NO_x control technique in new sources. Assuming dry controls will eventually be commercially available and can reduce NO_x emissions to meet the NSPS without adversely affecting CO and HC emissions, they will then be the much preferred control technique. Dry controls will be much simpler than wet controls, involving simply a different kind of combustor can. None of the ancillary equipment associated with wet controls will be required. Cost estimates, while difficult to accurately predict at this stage of development, are expected to be, at a maximum, the same as wet controls. One developer expects them to cost approximately 15 percent more than a conventional combustor can.

Ultimately, if catalytic combustion can be demonstrated in full scale engines, then it will probably become the preferred option. Emission reductions with this technique have been significant, approaching 98 percent. However, this technology is in its infancy and should not be considered a real possibility until the late 1980's.

A number of organizations, including EPA, have done air quality modeling studies to determine the effect that stationary gas turbines have on ambient air quality. Emissions from units burning various fuels, having different degrees of control, equipment configurations and meteorological conditions, were compared to the NAAQS. The details of these studies were previously reported in Section 6.2.3. In summary, it appears that most permutations of the above variables result in a very small impact on the NAAQS. Under certain unusual circumstances the NAAQS for CO and SO_2 was surpassed. While the NO_x NAAQS were never exceeded in these modeling studies (assuming zero baseline ambient NO_x), the NAAQS could easily be exceeded by certain turbine arrangements in regions that were approaching nonattainment.

EPA in Reference 6-2 has estimated that wet controls would reduce national NO_x emissions by 190,000 tons per year by 1982 and by 400,000 tons per year by 1987. It is estimated that electricity produced from these turbines would cost an additional 2 to 3 percent.

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SECTION 7

DATA BASE EVALUATION AND NEEDS

This section presents an evaluation of the data base which was used in assessing the environmental impacts of stationary gas turbines. Consideration was given to the sources of data as well as to the quantity and quality of the data applied to each element of this report. The value of completed and ongoing control technology research and development programs are also discussed, with much of the emphasis put on dry controls. It seems that as dry controls are developed and become commercially feasible, little additional effort will be expended on refining wet controls. Of course, wet controls are already capable, in principle and in many actual operations, of reducing NO_x emissions to below the proposed regulation of 75 ppm at 15 percent O_2.

In addition to discussing the environmental assessment data base, this section outlines various data requirements to more fully and accurately evaluate the total impacts due to NO_x controls on gas turbines. In defining these data needs, primary focus has been placed on development of standards support, control technology R&D, and on further testing and studies to upgrade the environmental assessment.

7.1 DATA BASE REVIEW

Water and steam injection are widely accepted by the gas turbine industry as valid means of controlling NO_x emissions. Indeed, water injection has been used for load augmentation since 1961 by industrial users. Numerous gas turbine units equipped with water injection have been sold, particularly to utility customers. However, since there are relatively few regional regulations controlling NO_x emissions, most of these users with water injection simply have not used it for appreciable lengths of time. Consequently we have had to rely to a great extent on information and data supplied by manufacturers, EPA and those few users who are required to meet a NO_x emission limit.

A substantial amount of good quality data regarding wet control emissions reduction was collected by EPA for use in the SSEIS (Reference 7-1). Results from certain additional emissions testing programs since the completion of the SSEIS have been added to this data base. These data support the general trends reported in the SSEIS regarding NO_x emission reduction and the relationships between percent NO_x reduction and the water/fuel ratio. Thus, these data in conjunction with other supporting data in the literature indicate that water and steam injection are viable control techniques for NO_x.

A significant amount of disparity was found in users, manufacturers and EPA estimates for costs of wet controls, both capital and operating cost estimates. Other than for large scale gas turbines where a few users could supply actual cost data, we have had to rely primarily on manufacturer's and EPA's cost estimates. Even for large scale units, data are sparse since most users are not required to control NO_x. Again, due to the lack of NO_x regulations and due to differences in accounting procedures, it is difficult to accurately predict any additional operating and maintenance costs. Day-to-day operations were found to have a major effect on the costs incurred by users. The most serious cost data gaps are with wet control costs for small and medium size turbines and with all aspects of cost estimates for dry controls on all size units.

As in the case with estimating NO_x control costs, it is also difficult to accurately predict the effect that wet controls have on gas turbine operations and maintenance. The best source for this type of information is, of course, the long term user. Of the users we have contacted, some of which have accumulated many thousands of hours of operation with wet controls, the majority seem to have few additional problems attributable to wet controls. On the other hand, some users have reported significant problems, usually related to the water injection equipment itself or to materials problems with hot components (i.e., deposits, corrosion and embrittlement). All sources agree that water injection imparts a fuel penalty on normal operations, thereby increasing the heat rate. A portion of this penalty may be offset by increases in power output. The variability in the reported data seems to be primarily a function of day-to-day operations and maintenance procedures. Furthermore, the data indicate that there is nothing inherent with water injection systems that would cause excessive problems. It also appears that proper operational and maintenance procedures can obviate most difficulties encountered with these systems.

Dry NO_x controls are in the development stages. Numerous specific designs are being applied to a few general NO_x control concepts with a common goal to design a gas turbine combustor that will control NO_x to the regulated limit, without sacrificing other pollutant emissions or combustion efficiency. Given the existing state of development, it is not possible to perform a comprehensive and accurate environmental analysis. We have had to rely almost totally on experimental combustor programs reported in the literature and some industry contacts to qualitatively assess the postulated effects of the most promising dry control concepts. Unfortunately, the available literature does not give the whole picture regarding evolving dry controls. Much of the design information is proprietary to the manufacturers and is not available. Further, the work conducted so far is generally on a single combustor rig although some full-scale demonstrations have been performed. Significant R&D effort will be required before these dry control concepts can be reliably applied to actual engines. The degree of R&D required will be determined by the sophistication of combustor rig experiments, how well actual combustor inlet conditions are simulated and how accurately actual engine conditions are duplicated. Moreover, once combustor rigs are scaled up to full size engines, long term reliability and life tests will have to be performed.

While the data indicate that the pollution reduction potential of catalytic combustion is extremely promising, this technology must only be considered as a long term control technique. As far as application to full scale engines is concerned, this technology is many years from fruition. Some manufacturers even voice skepticism that it will ever prove commercially viable.

The available data for all dry NO_x control techniques make only qualitative judgments and estimates possible when predicting costs, incremental emissions and operations and maintenance impacts. When assessing this report's evaluation, one must keep in mind that dry controls are an emerging technology and are at least two to four years from the first full scale application. Numerous changes in the preferred design, which could have a major impact on the predicted environmental effects, may occur.

7.2 DATA NEEDS

As users and manufacturers gain experience, additional data ought to be evaluated on a periodic basis during the life cycle of existing, modified and new stationary gas turbines. This is necessary due to the nature of the evolutionary process that dry NO_x control techniques are undergoing and the considerable lack of long term operating experience with wet controls. In this manner maximum benefit will be derived through use of emerging data to:

- Support standards development
- Support effects and control technology R&D
- Define needs for further testing to expand the data base
- Define needs for further studies to upgrade the environmental assessment.

There are specific areas where there appears to be a general lack of consensus regarding certain impacts from wet controls. These include: 1) water injection cost data for capital equipment, operating and maintenance expenses, 2) the cost/benefit ratio of wet controls for small gas turbines (<4 MW electrical output), 3) quantification of the fuel penalty due to increased heat rate and additional power output resulting from more mass throughout, and 4) quantification of the effect of NO_x controls on incremental emissions of pollutant species other than NO_x.

Wet control technology and its associated NO_x reduction potential are well developed and understood. In addition, wet controls will essentially become obsolete for new sources with the expected advent of dry controls by 1982. Dry controls, however, are an emerging technology, and there are many unanswered questions regarding incremental effects and associated costs. Manufacturers appear to be focusing in on the most effective dry control concept in reducing NO_x while minimizing incremental emissions and maintaining acceptable system efficiencies. The next critical step is scaling up to full size engines, assessing the various environmental impacts and developing long term operating experience.

At present, it seems clear that dry NO_x controls will be the preferred control technology option for new gas turbines within five years. Due to their present state of development, essentially no data regarding emission levels, control costs and operations and maintenance impacts exist for the application of dry controls to full scale engines. All of these data are required to perform a meaningful environmental assessment of dry NO_x control technology. As the direction of dry controls research becomes evident, additional testing programs can be suitably designed to provide the proper data base. Then, as dry controls become commercially feasible and users gain operating experience, any additional data gaps may be filled accordingly. The types of gaps will primarily be additional operating and maintenance costs that can only be accurately predicted through long term accounting of such expenditures. Only by such careful front-end tracking of dry control developments can a comprehensive environmental assessment be performed.

REFERENCE FOR SECTION 7

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